These are exciting days for oil and gas companies. Record prices and strong demand have delivered soaring profits. But, where and how companies invest their profits will determine who's successful in all price environments. We believe long-term winners invest in value.

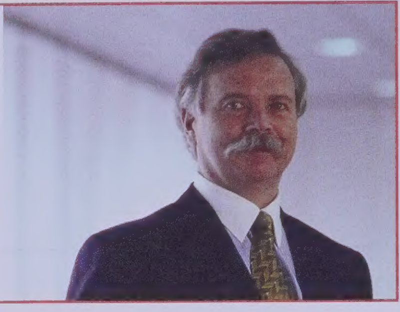
You own a stake in Nexen. see the value >

nexen

2004 ANNUAL REPORT

Fellow Shareholders

When a company focuses on value, long-term strategies take precedence over short-term thinking and project returns win over simple production growth. To us, creating value is ensuring maximum return for every dollar of capital we invest.



Over the past year, we've continued shifting away from high-cost maturing assets into regions where we're not just developing projects, we're building sustainable businesses. These growth regions—the Athabasca oil sands, Gulf of Mexico, Middle East, offshore West Africa, and most recently North Sea—are generally less mature and offer attractive fiscal terms. Wherever possible we've jumped in on the ground floor, we're gaining economies of scale and securing solid opportunities for future growth.

You can see the value this strategy is delivering: in our record results, in our attractive returns on capital, and in the superior production and returns our major development projects will deliver in the next three years. We're making great progress. With the North Sea acquisition, sanctioning of the Long Lake Project, first oil from Block 51 in Yemen, and more exploration success offshore West Africa and in the Gulf of Mexico, we have significant growth in hand.

Highlights

	2004	2003	2002
Capital Expenditures ($ millions)	1,681	1,494	1,625
Business Acquisitions ($ millions)	2,583	-	-
Production Before Royalties (mboe/d)	250	269	269
Production After Royalties (mboe/d)	174	185	176
Cash Flow from Operations ($ millions)	1,942	1,795	1,311
Cash Flow per Share ($/share)	15.10	14.50	10.71
Net Income ($ millions)	793	578	409
Net Income per Share ($/share)	6.17	4.67	3.34

Proved Reserves[1]

(mmboe)	Yemen	North Sea	Other Intl	US	Canada Conventional	Canada Bitumen	Syncrude Mining	Total
Dec. 31, 2003	192	-	11	126	192	5	285	811
Extensions and Discoveries	2	-	-	4	8	241	22	277
Acquisitions	-	130	-	-	1	-	-	131
Dispositions	-	-	-	-	(1)	-	-	(1)
Revisions	(22)	1	4	(7)	(14)	(246)	-	(284)
Production	(39)	(1)	(3)	(20)	(22)	-	(6)	(91)
Dec. 31, 2004	**133**	**130**	**12**	**103**	**164**	**0**	**301**	**843**

Probable Reserves[1]

(mmboe)	Yemen	North Sea	Other Intl	US	Canada Conventional	Canada Bitumen	Syncrude Mining	Total
Dec. 31, 2003	95	-	64	33	52	395	85	724
Extensions, Discoveries and Conversions	-	-	21	1	1	(241)	(16)	(234)
Acquisitions	-	123	-	-	-	-	-	123
Dispositions	-	-	-	-	-	-	-	-
Revisions	(46)	-	4	(20)	10	246	-	194
Dec. 31, 2004	**49**	**123**	**89**	**14**	**63**	**400**	**69**	**807**

Proved + Probable Reserves[1]

(mmboe)	Yemen	North Sea	Other Intl	US	Canada Conventional	Canada Bitumen	Syncrude Mining	Total
Dec. 31, 2004	**182**	**253**	**101**	**117**	**227**	**400**	**370**	**1,650**

1 Reserves represent Nexen's working interest before royalties using year-end pricing. See page 146 for more details. For reserves after royalties using year-end pricing, see page 114.

Cash flow $1.9 billion, up 8%
Net income $793 million, up 37%

Record Results

In 2004, we generated record financial results from strong commodity prices, high-netback production and outstanding contributions from our marketing group. Our cash flow increased 8% to a record $1.9 billion, and net income hit $793 million. (See my executive summary on page 29 of our 10-K for more details.)

With no hedges on production in 2004, we realized the full impact of strong commodity prices. However, production volumes were challenging and declined 6% after royalties from 2003. In Yemen, Masila began maturing and Canadian conventional production declined as we limited our investment to extract value rather than growing production. In both areas, we revised our proved reserves down slightly, reflecting this maturity. Both Ejulebe, offshore Nigeria, and Buffalo, offshore Australia were substantially depleted at year-end, and some of our Gulf of Mexico properties failed to deliver what we expected. Despite this, we produced a record fourth quarter in the Gulf, with Gunnison reaching full production and a third Aspen well on stream. Syncrude enjoyed a record production year with improved reliability and Guando in Colombia exceeded expectations. In December, we added 30,000 boe/d of high-margin barrels from our North Sea acquisition and Block 51 in Yemen.

Our cash margins are expanding—a true measure of value. As we've added more than 30,000 boe/d of low-cost, high-margin production from the deep-water Gulf of Mexico, we've increased the cash margin on our average barrel of production by 50% since 2002.

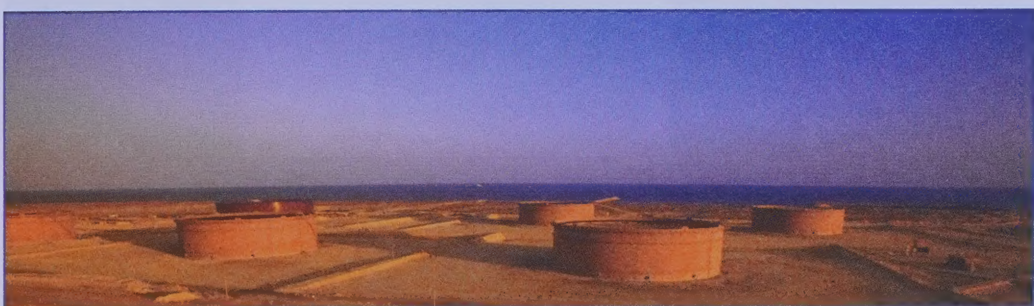
Although we expect relatively flat production in 2005, our margins should continue to improve, with new valuable barrels from the North Sea and Block 51. Assuming WTI of US$40, we expect 2005 cash flow of more than $2 billion, before factoring in our planned dispositions.

The continual upgrading of our asset base is significantly enhancing the cash flow and returns from our oil and gas business.

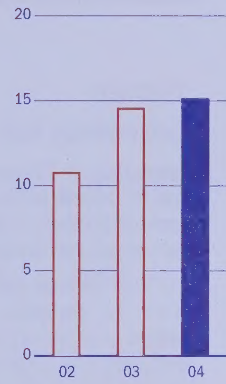
Our marketing group is also extending the value chain for our oil and gas operations. We had another outstanding year, increasing our presence in the US Midwest and Eastern Canada core markets. Today, we manage transport and delivery of over 585,000 barrels of oil and 5.1 billion cubic feet of gas per day. We continue to provide superior customer service and enter low-risk trading strategies that capitalize on price differences between various markets. Equally important, we gain exceptional market intelligence that ensures we receive a competitive price for our production and influences where we invest future capital.

In 2005, we plan to reinvest less than 20% of cash flow in our core assets to sustain production and cash flow. Most of our $2.6 billion capital program will focus on advancing our major development projects and drilling high-potential exploration wells in the Gulf of Mexico, North Sea, offshore West Africa and Yemen.

Let me walk you through our exciting initiatives.

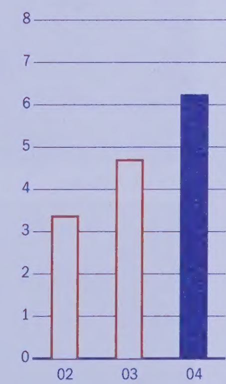


Record Cash Flow
($/share)



Over the past three years, our return on capital has averaged 17%.

Record Earnings
($/share)



world-class assets

Yemen

Extracting full value

Operating in Yemen for more than a decade has sharpened our technical skills, broadened our understanding of how to work effectively with local communities and governments, and delivered significant free cash flow.

We see exceptional value in this country. We expect Masila alone to generate another $1.4 billion of free cash flow before our agreement expires in 2011. In 2004, we saw the first signs of maturity here after 10 years of growth. We're managing the drilling pace to ensure we recover the remaining 20% of the reserves in the most efficient, cost-effective manner. We still have 150 drillable locations and expect to drill between 20 and 40 wells annually. In 2005, we estimate between 74,000 and 84,000 bbls/d of production before royalties net to us, and about $300 million of free cash flow. And there's still growth potential from deeper structures that we will continue testing in the next few years.

In 2004, first oil from our second producing block, East al Hajr (Block 51), came on stream ahead of schedule. We have two promising exploration wells here that require some additional testing. We plan to continue exploring to assess the block's full potential.

Even though we expect total Yemen production before royalties to decline, production after royalties is expected to remain constant year-over-year. This reflects the nature of our production sharing agreements where we enjoy further capital recovery from Block 51 volumes. Overall, we will continue to leverage our regional experience for other exploration or exploitation opportunities in the Middle East and North Africa.

We expect Masila to deliver
$1.4 billion
of free cash flow to Nexen over its remaining life. Block 51 adds to this.

mid-2005
Block 51
approximately 25,000 bbls/d

North Sea

New core area jump-starts growth

Our North Sea acquisition in December was the largest transaction in our history. We paid $2.6 billion for the Buzzard discovery, Scott and Telford producing fields, four regional discoveries, and over 700,000 unexplored acres nearby. We gained an experienced operating company with an excellent track record, and we became a significant regional operator.

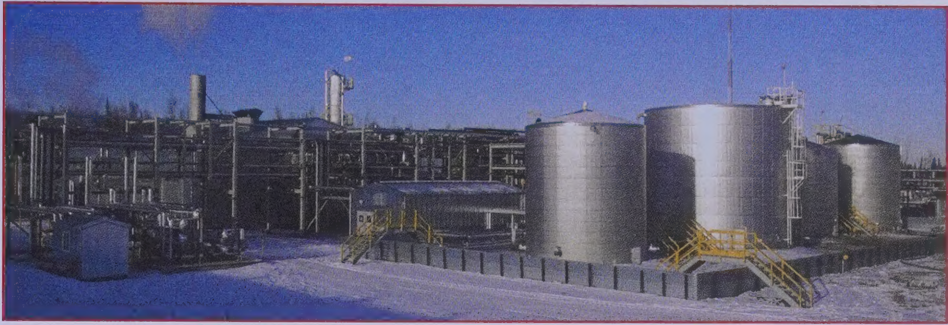
Some were surprised by this apparent shift in our exploration-driven strategy. To me, there is no inconsistency. Buzzard is a major discovery, a world-class reservoir—exactly the type of opportunity our exploration program is geared to provide. When we evaluated these North Sea assets, we estimated proved and probable reserves of 253 mmboe, net to us (130 mmboe proved). Over time, we believe we could easily recover more from Buzzard's high-quality reservoir, based on similar fields in the area. The economics are outstanding, as production is royalty-free. At its peak, Buzzard should generate about $1.4 billion of new cash flow each year, assuming WTI of US$40.

Buzzard is approximately 60% complete, and on-schedule for first production in late-2006, ramping up to 80,000 boe/d net to us in 2007. The additional exploitation opportunities at Scott and Telford and tie-in of surrounding smaller discoveries could double our non-Buzzard production from the North Sea by 2008. We also plan to drill a number of exploration wells in 2005 for future growth that could be tied into our infrastructure.

This acquisition jump-starts our growth in the North Sea. It's the best way to enter a new region—by building on an existing sustainable business, together with the people who helped build it.

At its peak, Buzzard should generate
$1.4 billion
of new cash flow each year, assuming WTI of US$40.

late-2006
Buzzard
royalty-free 80,000 boe/d in 2007



innovative technology

Athabasca Oil Sands

A legacy asset in the making

Our Long Lake Project is the fourth major oil sands project in the Athabasca region of Western Canada. Yet it's the first to fully integrate SAGD and upgrading processes to extract maximum value from the massive resource here. We will create a high-value product, more sought after by refiners than raw bitumen. We will upgrade bitumen in the field, eliminating the diluent cost normally required to transport bitumen. And we will generate our own fuel, so we're not buying expensive natural gas. These factors help create a $4 to 7/bbl operating cost advantage over other projects, assuming NYMEX gas of US$3/mcf. With the strong gas prices we are experiencing, this cost advantage grows.

Apply this to our estimated 5 billion barrels of recoverable bitumen resource here and the magnitude of our advantage is striking. With no exploration risk and over 40 years of stable free cash flow from long-life reserves, this is the type of opportunity you build a long-term business around.

Long Lake is just phase one, and will develop 10% of our recoverable bitumen resource. The project is on schedule and on budget. We have purchased all major equipment and most bulk materials. Module fabrication and assembly is underway. Site construction will begin later this spring and drilling of the commercial SAGD production wells is ahead of schedule. Results from our pilot testing have prompted us to accelerate 13 well pairs to ensure certainty and reliability of bitumen production when we begin upgrading. This will bring the producing well count to 81 well pairs and accelerates $98 million of planned future capital. So while total project costs remain the same, our share of capital costs for the project is now estimated at $1.75 billion. We are on track for bitumen production in late-2006, and upgrader startup in 2007.

With project sanctioning in February 2004, we booked 200 mmbbls of proved synthetic crude reserves. However, we determined that, under SEC regulations, we are required to represent our Long Lake reserves as bitumen rather than synthetic crude, and to use year-end pricing to determine proved reserves. A combination of wide heavy oil differentials, high natural gas prices and very high diluent costs on December 31, 2004 resulted in low bitumen netbacks. As a result, under these price assumptions, we wrote off all our proved bitumen reserves for Long Lake at year-end. Let me emphasize that this is a case where regulatory requirements do not allow us to accurately portray our business. We're not just producing bitumen barrels. Our integrated process upgrades bitumen into a premium synthetic crude, which virtually eliminates our exposure to heavy oil differentials, diluent and natural gas costs.

We've captured the resource, the economics are attractive, and we're moving full-steam ahead.

Elsewhere in Canada, Syncrude's Stage 3 expansion is expected to be completed and on stream in 2006. We are also evaluating other unconventional resources including coal bed methane and enhanced heavy oil recoveries. We have a number of pilot projects underway and hope to report positive results in the coming months and years.

Apply our $4-7/bbl cost advantage* to our estimated

5 billion barrels

of recoverable bitumen.

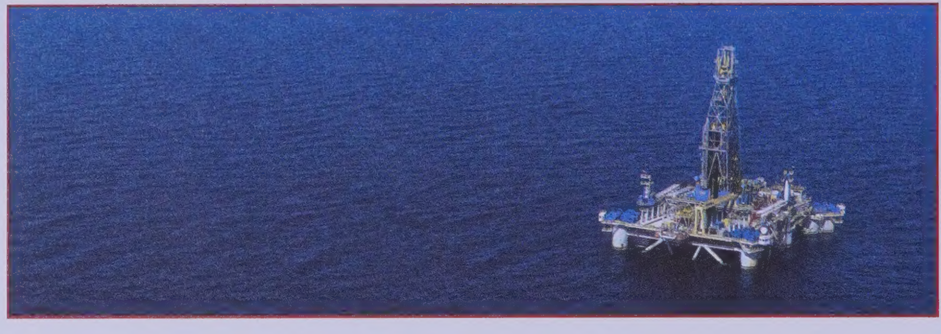
* Assuming US$3 NYMEX

< see the value

2007

Long Lake on stream

climbing to 30,000 bbls/d of premium synthetic oil



focused exploration

Offshore West Africa

Tapping into a significant resource

Offshore West Africa offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. For us, the highlight is OPL-222 offshore Nigeria, where to date, we've drilled eight successful wells at Usan, Ukot and Usan West. This includes a significant discovery and a successful appraisal drilled in 2004 in the area west of Usan. With each well drilled, the value of the block continues to grow. Development plans for Usan are being prepared to submit to the government and we are eager to move forward with this plan. In the meantime, we continue to see a number of additional prospects here and have plans for further exploration drilling this year.

Elsewhere in the region, we continue to explore on OML-115, offshore Nigeria and on Block K, offshore Equatorial Guinea. Although we have not yet found significant hydrocarbons, we remain encouraged given significant discoveries in the area and plan to test a prospect on each block in 2005.

The value of OPL-222 grows with every well drilled.

see the value >

Deep-water success in the Gulf of Mexico leads our largest exploration program ever in 2005, with over 20 high-potential wells planned.

Gulf of Mexico

Building on deep-water success

The Gulf of Mexico is our area of greatest growth in the past couple of years. We've brought on two deep-water discoveries, Aspen and Gunnison, adding over 30,000 boe/d of new production at netbacks over $35/boe. Both are contributing significant free cash flow and Aspen has paid for itself in just over two years, while producing only 30% of its proved reserves.

The Gulf is a great place to continue growing our business, with large discoveries, high success rates and attractive fiscal terms. We're focused on exploring three areas: deep-shelf gas, deep-water prospects near existing infrastructure and deep-water, sub-salt plays. Last year, half of our exploration program was allocated here, which yielded small discoveries at Tobago and Dawson Deep.

A key success factor in achieving exploration success is maintaining an active drilling program. Our drilling pace in the Gulf was disappointing in 2004, as we had a number of delays on planned wells. With most rigs secured and partner approvals in place, we're marching forward in 2005 with our most active exploration program ever. Currently, we have three wells drilling and plan up to ten more in the Gulf this year, including three very large deep-water, sub-salt prospects. This program should give us a good sense of the potential of our US exploration strategy.

So far in 2005, we've already reported two successes in the deep-water Mississippi Canyon area. At Wrigley, we found 90 gross feet of high-quality gas pay and plan to tie-back the well to existing infrastructure. First production is anticipated on stream by mid-2006. At Anduin, we discovered 48 feet of gross oil pay and are side-tracking the well to determine the reservoir size and development options. So, while it appears we will likely be delayed in achieving our Gulf production target of 100,000 boe/d by year-end 2006, we are confident that the Gulf will continue to generate significant value for us.

Company-wide, we plan to invest $435 million in exploration in 2005 and drill a number of high-potential wells: up to ten in the Gulf, between four and six in the North Sea, four in Yemen and four offshore West Africa.

In 2007, we expect to produce between 300,000 and 350,000 boe/d before royalties and generate cash flow of more than $3 billion, assuming WTI of US$40/bbl.

Growth on the Horizon

Developing four major projects at once is no small feat. They each take time, financial discipline and superior technical skills. Today, we have over $3 billion invested in projects yet to deliver a drop of oil—what we call "development capital behind pipe". By late-2006, this investment will peak to about $5 billion, half our current enterprise value, as we bring Buzzard and Long Lake on stream.

Our current proved reserve estimates capture only a sliver of the value we're developing with these projects. Our proved reserve additions of 123 million boe in 2004 relate primarily to the North Sea assets acquired and Syncrude's Stage 3 expansion. As I mentioned, we have yet to book proved reserves for Long Lake. And there's more to come as the Buzzard development proceeds and OPL-222 is sanctioned. The value here is significant. To date, we've booked 190 million boe of proved and 612 mmboe of probable reserves for our major projects. The probable reserves alone amount to three-quarters of our current proved reserves. They are high-quality and depend primarily on timing to be reclassified to proved reserves.

The incremental production and cash flow from our investment will be impressive. In 2007, we expect to produce between 300,000 and 350,000 boe/d before royalties and generate cash flow of more than $3 billion, assuming WTI of US$40/bbl.

Most of these barrels have little or no royalties and generate significantly higher cash margins than our current production. After royalties, this translates into a compound production growth rate of between 15% and 20% over the next few years. These projects all earn their cost of capital at oil prices in the low US$20's. Of course if prices are higher, we have more capacity to repay debt or take advantage of further growth opportunities.

Here's our growth profile on the horizon:

2005 Yemen's Block 51 reaches close to 25,000 bbls/d mid-year

2006 Syncrude Stage 3 expansion adds 8,000 bbls/d

Buzzard on stream late in year, ramping up to 80,000 boe/d in 2007

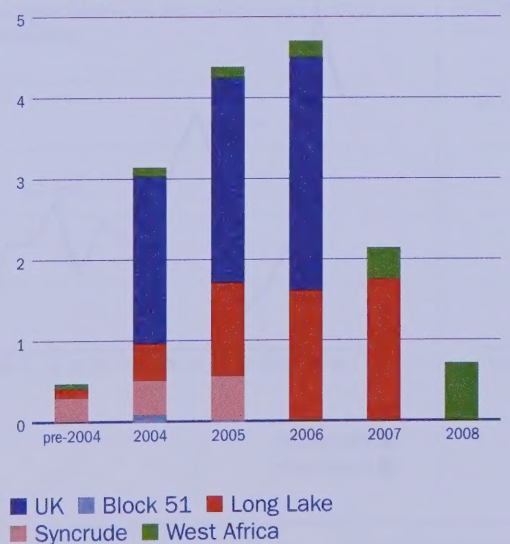
Long Lake bitumen production begins

2007 Long Lake upgrader on stream, climbing to around 30,000 bbls/d

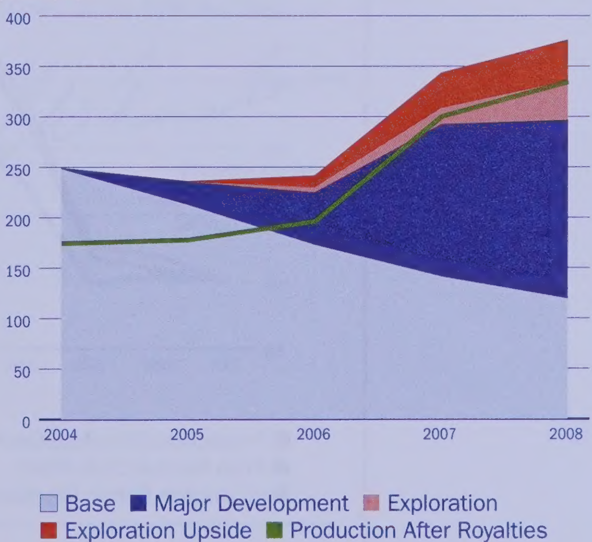
2008 Non-Buzzard North Sea production doubles to 40,000 boe/d

Over these years, our average royalty rate is expected to drop from 30% to just over 10%.

Development Capital Behind Pipe
(Cdn $billions)

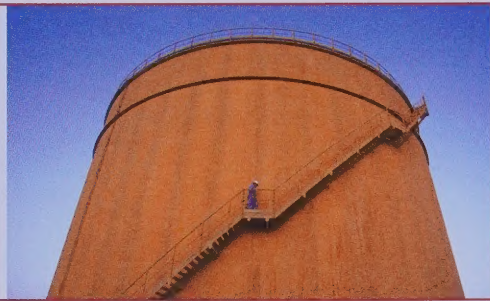


Future Production Growth
(mboe/d)



We expect per share production and cash flow to soar starting in 2007, once Buzzard and Long Lake are on stream.

Measuring Value



see the value >

Even with the acquisition, our net debt is just 2.2 times our 2004 cash flow from operations. That's before $1.5 billion in planned dispositions.

Our put options provide a floor price for 60,000 bbls/d of production in 2005 and 2006, while we retain 100% of price upside.

Per share growth in production and cash flow measures the true value of our investment. We expect production per share after royalties to grow at an average compound rate of 27% and cash flow per share at 25%, over the next five years. These rates are debt-adjusted to isolate growth for shareholders after servicing the debt that funded this growth.

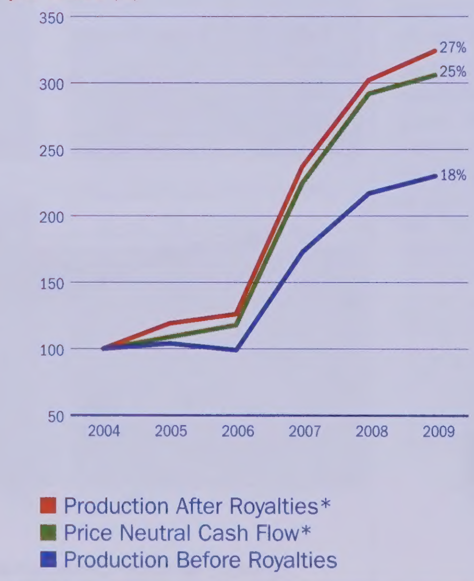
As the graph below illustrates, the modest growth in 2005 and 2006 reflects two important points: 1) we are shifting the focus of our investment from maturing assets to longer-term projects including Buzzard and Long Lake; and 2) we increased debt levels to fund the North Sea acquisition. We've used debt in the past to finance the Masila development in 1993 and the Wascana acquisition in 1997. Each time we've had a plan in place and brought debt levels down quickly.

In 2005, we plan to reduce our debt by selling $1.5 billion in mature non-strategic assets. We have retained financial advisors to advise us on market conditions and alternative structures for maximizing the value of our chemicals assets and certain Canadian conventional assets.

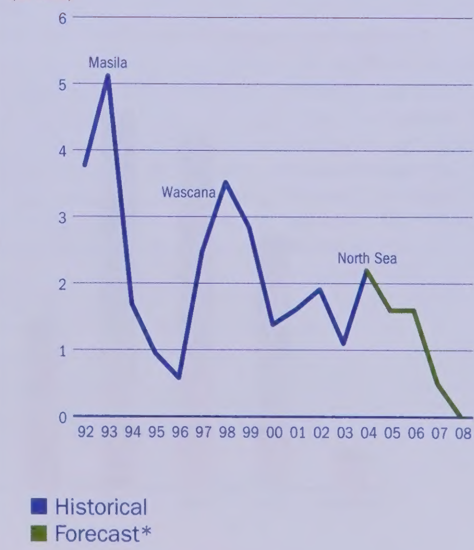
We have also purchased financial assurance with put options which provide a floor price for 60,000 bbls/d of net oil production in 2005 and 2006. This will ensure strong cash flows through these important investment years while retaining 100% of the price upside for shareholders. Also, our strategic decision not to hedge, based on our analysis of futures markets, preserves this price upside. Since 1998, we have realized $1 billion more in cash flow than if we would have undertaken a hedging program similar to those undertaken by many of our competitors. We'll continue to monitor the markets to ensure our strategy captures maximum value for our production.

We are confident that our strong balance sheet and robust financing strategy can handle these higher debt levels. Once Long Lake and Buzzard start generating cash flow in 2007, the debt will be reduced quickly and value for shareholders should soar.

Debt-Adjusted Production & Cash Flow per Share (%)



Net Debt to Cash Flow from Operations (times)



* Assume US$40 WTI

We see value in long-term partnerships—with employees, communities, governments and all stakeholders.

Valuing Partnerships

Equally important to our strategy is the value of human capital, and I continue to be impressed with the determination and skill of our people. Some are dedicated to getting the last valuable barrel out of our maturing assets, while others are building mega projects. Some are exploring for our next big find and others are ensuring we provide transparent, accurate results to all stakeholders. And many more are supporting these functions. Yet, among this diversity lies a common goal: to increase long-term shareholder value in a responsible way.

I am proud of our accomplishments and eager to work together to overcome our challenges.

Our employees enjoy working at Nexen. For four consecutive years, they have selected us as one of the 50 best companies to work for in Canada. In a separate national survey, we've been selected as one of the top 100 employers.

We're also being recognized for our governance practices and attribute this primarily to the support and excellent strategic guidance provided by our well-informed, independent Board. Out of 2,588 companies assessed around the world by New York's GovernanceMetrics International, we were one of only 26 that received a perfect score. We are proactively meeting or exceeding all rules mandated by securities regulators and Sarbanes-Oxley.

When building sustainable businesses, we look beyond pure economic benefits and address the safety, environment and social impact of our decisions. Operating with integrity and transparency has created opportunities that would otherwise not be available. We've been successful at fostering partnerships with local communities, governments and other stakeholders where we can all benefit. We've been included on the Dow Jones Sustainability Index for four years, reflecting investor confidence in our approach. I encourage you to read our Sustainability Report to learn about our sustainable business practices and our commitment to continuous improvement. We believe companies that follow sustainable business practices outperform, in the long term, those with narrower priorities.

When I envision Nexen in three years, I see higher margin barrels from new projects. I see us leading the oil sands development, operating major projects in the deep-water Gulf and the North Sea, and maximizing value from Yemen. I see us developing new opportunities for future growth. What gets us from here to there is a commitment to our strategies—investing wisely today to create long-term shareholder value.

As a company of over 3,000 employees, we are excited about our future. I look forward to sharing our progress with you throughout the year and, in particular, at our AGM in Calgary on April 27.

Charlie Fischer
President and CEO
March 1, 2005

nexen

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e: grant_dreger@nexeninc.com

Learn More

Communicating with stakeholders is about creating understanding. We want you to understand our plans, progress and results. Our 10-K and other information that follow discuss our:

We also produce other documents to assist you:

Corporate Profile: Gain an overview of Nexen.

Proxy Circular: Learn about our board, officers, corporate governance practices and details about the AGM on April 27, 2005.

Statistical Supplement: Download detailed historical operating and financial information for Nexen and our segmented operations.

Sustainability Report: Learn about our way of doing business and progress towards improving our safety, environment and social responsibility performance.

Check out the investor toolkit at www.nexeninc.com/investor_centre to view these documents online or to order a hardcopy. Our website also contains information including: quarterly reports, news releases, investor presentations, conference call scripts and more.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) of THE SECURITIES EXCHANGE ACT OF 1934

For the year ended December 31, 2004

Commission File Number 1-6702

nexen

NEXEN INC.

Incorporated under the Laws of Canada

98-6000202
(I.R.S. Employer Identification No.)

801 – 7th Avenue S.W.
Calgary, Alberta, Canada T2P 3P7
Telephone - (403) 699-4000
Web site - www.nexeninc.com

Securities registered pursuant to Section 12(b) of the Act:

Title	Exchange Registered On
Common shares, no par value	The New York Stock Exchange
	The Toronto Stock Exchange
Subordinated Securities, due 2043	The New York Stock Exchange
	The Toronto Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No ______

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
Yes ✓ No ______

On June 30, 2004, the aggregate market value of the voting shares held by non-affiliates of the registrant was approximately Cdn $6.7 billion based on the Toronto Stock Exchange closing price on that date. On January 31, 2005, there were 129,415,565 common shares issued and outstanding.

TABLE OF CONTENTS

Special Note to Canadian Investors - see page 72

Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided in tabular format. Volumes and reserves include Syncrude operations unless otherwise stated.

Below is a list of terms specific to the oil and gas industry. They are used throughout the Form 10-K.

/d = per day
bbl = barrel
mbbls = thousand barrels
mmbbls = million barrels
mmbtu = million British thermal units
km = kilometre
MW = megawatt
mboe = thousand barrels of oil equivalent
mmboe = million barrels of oil equivalent
mcf = thousand cubic feet
mmcf = million cubic feet
bcf = billion cubic feet
WTI = West Texas Intermediate
NGL = natural gas liquid

In this 10-K, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6mcf/1bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf/1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

The noon-day Canadian to US dollar exchange rates for Cdn $1.00, as reported by the Bank of Canada, were:

(US$)	December 31	Average	High	Low
2000	0.6666	0.6733	0.6973	0.6413
2001	0.6279	0.6458	0.6695	0.6241
2002	0.6331	0.6369	0.6618	0.6199
2003	0.7738	0.7135	0.7738	0.6350
2004	0.8308	0.7683	0.8493	0.7159

On January 31, 2005, the noon-day exchange rate was US$0.8078 for Cdn $1.00.

Electronic copies of our filings with the Securities Exchange Commission (SEC) and the Ontario Securities Commission (OSC) (from November 8, 2002 onward) are available, free of charge, on our website (www.nexeninc.com). Filings prior to November 8, 2002 are available free of charge, upon request, by contacting our investor relations department at (403) 699-5931. As soon as reasonably practicable, our filings are made available on our website once they are electronically filed with the SEC or the OSC. Alternatively, the SEC and the OSC each maintain a website (www.sec.gov and www.sedar.com) that contain our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the OSC.

Scott platform, UK North Sea

contents

PART 1

Items 1 and 2. Business and Properties

ABOUT US

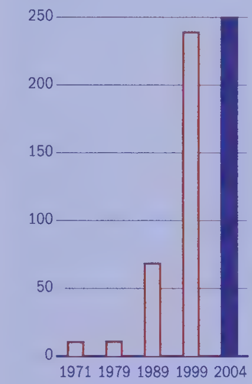
Nexen Inc. (Nexen, we or our) is an independent, Canadian-based, global energy and chemicals company. Previously Canadian Occidental Petroleum Ltd., we were formed in Canada in 1971 from the reorganization of two Occidental Petroleum Corporation (Occidental) subsidiaries. We combined their Canadian crude oil, natural gas, sulphur and chemical operations. We've grown from producing 10,700 boe/d before royalties with revenues of $26 million in 1971 to 249,600 boe/d before royalties (including Syncrude production) and revenues of $3.9 billion in 2004. We achieved this growth through exploration success and strategic acquisitions. Through over 30 years of operations, we have been profitable every year, but one, and have been paying quarterly dividends consecutively since 1975.

Nexen—an independent, Canadian-based global energy and chemicals company.

In the 1970s, we expanded our Western Canadian assets and entered the US Gulf of Mexico. We finished this decade with production of approximately 11,000 boe/d before royalties and revenues of $126 million.

In the 1980s, we acquired Canada-Cities Service, Ltd. in 1983, which doubled our size, and included an interest in the Syncrude Joint Venture, our entry into the Athabasca oil sands. Acquisitions of Cities Offshore Production Co. in 1984, and Moore McCormack Energy, Inc. in 1988, further increased our presence in the Gulf of Mexico. We finished this decade with production of approximately 68,600 boe/d before royalties and revenues of $591 million.

Production Before Royalties
(mboe/d)



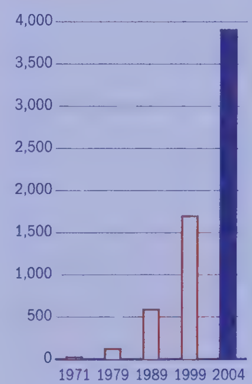
In the 1990s, we had two defining moments: discovering oil on the Masila block in Yemen and acquiring Wascana Energy Inc. The first of 17 fields at Masila was discovered in 1991, and Masila has produced over 825 million barrels since start-up. Our 1997 purchase of Wascana Energy Inc. almost tripled our Canadian production, with our Hay discovery in northern B.C. increasing this further. In 1998, we entered Australia with an interest in the offshore Buffalo field and entered Nigeria as the operator of the Ejulebe field. Also in 1998, we discovered Ukot on OPL-222, offshore Nigeria, the first of several discoveries to date on the block. We finished this decade with production of approximately 239,200 boe/d before royalties and revenues of $1.7 billion.

So far in the 21st century, we have made a number of discoveries and two strategic acquisitions. In 2000, we discovered Gunnison in the deep-water Gulf of Mexico and Guando in Colombia. In that same year, we agreed with Ontario Teachers' Pension Plan Board (Teachers) and Occidental, to purchase Occidental's 29% interest in us. Teachers purchased 20.2 million common shares and we repurchased the remaining 20 million common shares for $605 million. We also exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemicals operations. In addition, we changed our name to Nexen Inc. The following year, we discovered Aspen in the deep-water Gulf and signed a joint venture agreement with OPTI Canada Inc. to develop, produce and upgrade bitumen at Long Lake. On OPL-222, offshore Nigeria, we discovered Usan, the second discovery on the block, in 2002. In 2003, we discovered two fields on Block 51 in Yemen. In December 2004, we acquired EnCana Corporation's U.K. subsidiary, providing us with strategic operatorship of the Buzzard discovery and the producing Scott and Telford fields in the North Sea. Now in 2005, we are developing major projects and continuing an active exploration program for future growth.

For financial reporting purposes, we report on four main segments:

- Oil and Gas
- Syncrude
- Oil and Gas Marketing and
- Chemicals

Revenues
(Cdn$ millions)



Our Oil and Gas operations are broken down geographically into the US Gulf of Mexico, North Sea, Canada, Yemen and Other International (Colombia, offshore West Africa, and Australia). Results from our Long Lake Project are included in Canada. Syncrude is our 7.23% interest in the Syncrude Joint Venture. Marketing includes our growing crude oil, natural gas and power marketing business in North America and southeast Asia. Chemicals includes operations in North America and Brazil that manufacture, market and distribute sodium chlorate, caustic soda and chlorine.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appears in Note 18 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

STRATEGY

Our goal is to grow long-term value for shareholders.

Our goal is to grow long-term value for shareholders. We define value growth as increasing reserves, production and cash flow over the long term, measured on a debt-adjusted per share basis. This basis reflects the true growth realized by our shareholders. To accomplish this, we are creating sustainable businesses through exploration, technology application, strategic acquisitions and capital discipline.

As conventional basins in North America mature, we are transitioning our operations towards major projects in mature basins, exploration in less mature basins and exploitation of unconventional resources. Projects are focussed in the North Sea, Athabasca oil sands, Gulf of Mexico, offshore West Africa and the Middle East – basins we believe have attractive fiscal terms and significant remaining opportunity.

Our major projects typically have an extended period of time between sanctioning and first production due to their location and scale. These time lags cause non-linear growth year-over-year and significant up-front capital investment prior to realizing any production or revenues. We fund projects by maximizing cash flow from our producing assets, using various financial instruments, and selling non-core assets into attractive markets. We intend to dispose approximately $1.5 billion of assets in 2005 to help pay for our North Sea acquisition.

We also continue an active exploration program for future growth. We primarily explore in areas where we have existing production or infrastructure, or we have had recent exploration success.

We are transitioning our operations towards major projects in generally less mature basins and unconventional resources.

In creating sustainable businesses, we are committed to good corporate governance and social responsibility. We believe companies that follow sustainable business practices outperform those with narrower priorities. We foster dialogue with stakeholders about our operational opportunities and challenges, from exploration to production to reclamation. Our goal is to help stakeholders become engaged participants in a continuing consultation process, while balancing their multiple, and sometimes conflicting, goals.

UNDERSTANDING THE OIL AND GAS BUSINESS

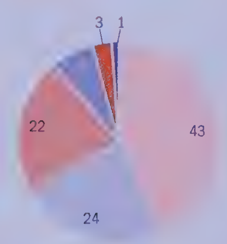
The oil and gas industry is highly competitive. With strong global demand for energy, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price products command at market based on quality and marketing efforts. Our goal is to extract the maximum value from each barrel of oil equivalent, so every dollar of capital we invest generates an attractive return.

Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to mitigate these impacts by investing in projects that we believe will generate positive returns at low commodity prices.

We also have a broad customer base for our crude oil and natural gas. Alternative customers are generally available, and the loss of any one customer is not expected to have a significant adverse effect on the price of our products or our revenues. Oil and gas producing operations are generally not seasonal. However, demand for certain of our products can have a seasonal component, which can impact price. In particular, heavy oil generally experiences higher demand in the summer months for its use in road construction and natural gas generally experiences higher demand in the winter heating months.

We manage our operations on a country-by-country basis reflecting differences in the regulatory and competitive environments and risk factors associated with each country.

2004 Production Before Royalties (%)

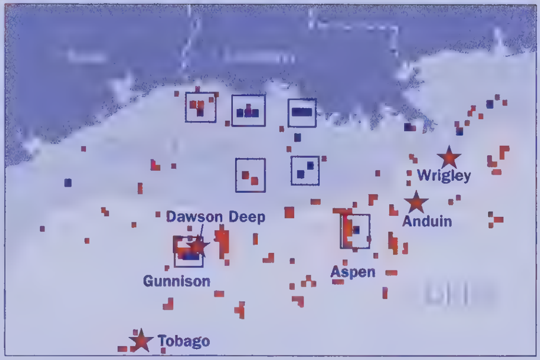


OIL AND GAS OPERATIONS

We have oil and gas operations in Western Canada, the US Gulf of Mexico, Yemen, the North Sea, offshore West Africa, Colombia and Australia. We also have operations in Canada's Athabasca oil sands which produce synthetic crude oil. We operate most of our production, and continue to develop new growth opportunities in each area, by actively exploring and applying technology.

Gulf of Mexico—United States (US)

The Gulf of Mexico is Nexen's fastest growing region, with over 30,000 boe/d before royalties of high margin production added from our deep-water Aspen and Gunnison fields in the past two years.



■ Producing Blocks
■ Exploration Blocks
□ Main Producing Fields
★ New Discoveries

Large discoveries, high success rates, production infrastructure and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective sources for oil and gas. The deep-water prospects generally have multiple productive horizons and high production rates, which reduces risk and improves economics. Technology to find, drill, and develop discoveries is rapidly progressing and becoming more cost effective. And, the deep-water Gulf is relatively close to infrastructure and continental US markets, allowing discoveries to be brought on stream in a reasonable period of time.

Our strategy in the Gulf is to explore for new reserves, acquire assets with potential, and exploit our existing asset base. We focus our exploration program on three strategic areas:

- deep-shelf gas prospects;
- deep-water prospects near existing infrastructure; and
- deep-water, sub-salt plays with potential to become new core areas.

In the US, we've added 30,000 boe/d before royalties of high-margin production in the last two years.

These areas are relatively under-explored, have potential for large discoveries, and have attractive fiscal terms. The shorter-cycle times for shelf gas and deep-water prospects near infrastructure complement the longer-cycle times for deep-water, sub-salt plays.

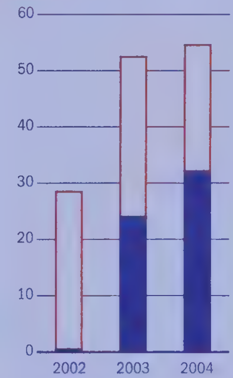
When we first entered the deep-water, we partnered with large experienced operators to improve our skills and understanding. A trade-off of this strategy was not controlling the timing of drilling programs. Our goal is to operate even more of our own deep-water properties and exploration wells so that we can manage the pace of activity. In 2004, we invested $400 million on exploration and development activities to further our strategy. We plan to invest approximately $315 million in 2005.

In 2004, we produced approximately 54,700 boe/d before royalties (47,500 after royalties), representing about 22% of Nexen's total production. Proved reserves of 88 mmboe (103 before royalties) at year-end 2004 were about 20% of Nexen's total proved oil and gas reserves after royalties. Our production and reserves in the Gulf are primarily concentrated in five shallow-water fields and two deep-water fields. We operate most of this production, and hold varying interests on 182 undeveloped federal lease blocks.

US Production

	2004		2003		2002	
(mboe/d)	Before Royalties	After Royalties	Before Royalties	After Royalties	Before Royalties	After Royalties
Shallow-water	22.6	18.8	28.5	23.7	28.1	23.2
Deep-water	32.1	28.7	24.0	21.7	0.5	0.5
Total	**54.7**	**47.5**	**52.5**	**45.4**	**28.6**	**23.7**

US Production Before Royalties
(mboe/d)



Royalty rates on our US production average 17% for shallow-water volumes and 10% for deep-water volumes. We qualify for royalty relief at our deep-water Aspen and Gunnison fields on the first 87.5 mmboe of production, making this production very attractive. We are subject to royalties at Gunnison if the annual commodity prices are higher than threshold prices set by the US Department of the Interior's Minerals Management Service. Royalties on other Gulf and state-water properties range from 12.5% to 25%. US taxable income is subject to federal income tax of 35% and state taxes ranging from 0% to 8%.

Weather is a risk in the Gulf of Mexico, specifically tropical storms and hurricanes. They can damage facilities, interrupt production, and delay exploration and development programs, beyond the few days of the storm itself. In September 2004, we shut-in 45,000 boe/d of production before royalties for three days, as Hurricane Ivan passed through. No significant damage was sustained at our facilities and full production was restored shortly thereafter. In October 2002, we suffered extensive facilities damage at Eugene Island 295 from Hurricane Lili. Production was restored there in early 2003.

SHALLOW-WATER PRODUCTION

Our shelf producing assets are offshore Louisiana primarily in five 100% owned fields: Eugene Island 18, Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 302/320 and Vermilion 76 (consisting of blocks 65, 66 and 67). We continue to exploit these assets, and look for other opportunities on the shelf. Most of our 2004 shelf development operations focused on increasing production at Vermilion 76 and 302/320, through development drilling activities.

DEEP-WATER PRODUCTION

Our deep-water production comes from our 100% operated Aspen field and our 30% non-operated Gunnison field. Our Gunnison SPAR production facility has excess capacity, leaving room for growth from exploration and processing of third-party volumes.

Aspen

Aspen achieved payout in just over 2 years.

Aspen is located on Green Canyon Block 243 in 3,150 feet of water. The project was developed using sub-sea wells tied back to the Shell-operated Bullwinkle platform 16 miles away. Production began in December 2002. By tying-in a third Aspen development well in July 2004, we increased 2004 production by 11,000 boe/d before royalties to 27,200 boe/d before royalties at year-end (24,600 after royalties), of which 14% was natural gas. There are no significant capital plans for Aspen in 2005. We achieved payout on the full Aspen project in early-2005, just over 2 years from first production.

Our Gunnison SPAR has capacity for future discoveries and third-party volumes.

Gunnison

Gunnison is located in 3,100 feet of water, and includes Garden Banks Blocks 667, 668 and 669. The first discovery was in May 2000 on Garden Banks Block 668, and the second in June 2001 on Garden Banks Block 667.

Gunnison began production in December 2003 through a truss SPAR platform that can handle 40,000 barrels of oil per day and 200 million cubic feet of gas per day. Our share of 2004 production before royalties was approximately 9,300 boe/d (8,200 after royalties). During 2005, we plan to drill and tie-in two additional development wells.

EXPLORATION

In 2004, half of our exploration budget was invested in the Gulf. The results in 2004 were mixed with four small discoveries and five abandoned wells:

Well	Location	Interest (%)	Results
Dawson Deep	Garden Banks 625	15	discovery expected to begin producing late-2005 through sub-sea tie-back to Gunnison
Tobago	Alaminos Canyon 858/859	13.34	discovery temporarily abandoned; possibly part of future regional development
Wrigley	Mississippi Canyon 506	50	gas discovery expected to begin producing in mid-2006
Anduin	Mississippi Canyon 754/755	50	encountered oil shows; side-tracking to delineate
Shark	South Timbalier 174	40	well abandoned
Crested Butte	Green Canyon 242	100	well abandoned as oil shows were close to salt; further work required to see if side-track warranted
Main Pass 240	Main Pass 240	45	well abandoned; found non-commercial quantities
Fawkes	Garden Banks 303	33⅓	well abandoned; found non-commercial quantities
Wind River	West Cameron 335	50	well abandoned

In 2004, we also increased our deep-water undeveloped land position to 148 blocks, by acquiring 19 blocks. We expect this acreage, plus new opportunities, to sustain our current level of exploration drilling.

We are in the midst of our most active Gulf exploration program ever, with two wells drilling and two more to begin drilling in the first half of 2005. Wells currently drilling with results expected in the first half of 2005 include:

Well	Location	Interest (%)	Operator Status	Strategy
Big Bend	Mustang Island A-110	50	non-operated	deep-shelf gas
Vrede	Atwater Valley 223/224/267/268	25	non-operated	deep-water

We expect to drill other deep-shelf gas and deep-water prospects in 2005, the most significant deep-water prospects are at Pathfinder (25% interest) and Knotty Head (25% interest).

We are in the midst of our strongest Gulf exploration program ever.

North Sea—United Kingdom (UK)

On December 1, 2004, we acquired assets in the UK North Sea for US$2.1 billion in cash subject to certain adjustments. This acquisition was completed by purchasing all outstanding shares of EnCana (UK) Limited. We acquired a 43.2% operated interest in the Buzzard development, operated interests in the Scott and Telford producing fields, the Scott production platform, interests in several satellite discoveries and over 700,000 net undeveloped exploration acres. We also acquired the management and technical teams that found and continue to develop Buzzard. From this acquisition we booked 130 mmboe of proved reserves (130 before royalties) comprising 29% of Nexen's total oil and gas reserves after royalties.

Field	Location	Interest (%)	Operator Status	Comments
Buzzard	Blocks 19/10, 20/6, 19/5a, 20/1s	43.2	operated	expected on stream late-2006 ramrping up to 80,000 boe/d our share in 2007
Scott	Blocks 15/21a, 15/22	41	operated	producing field with exploitation opportunities
Telford	Blocks 15/21a, 15/22	54.3	operated	producing field with exploitation opportunities
Ettrick	Blocks 20/2a, 20/3a	80	operated	discovery near Buzzard
Farragon	Block 16/28	20	non-operated	expected on stream late-2005 at 3,000 boe/d our share
Perth	Block 15/21a	42	operated	discovery near Scott
Black Horse	Block 15/22	56	operated	discovery near Scott
Bugle	Block 15/23d	80	operated	discovery near Scott

This acquisition establishes us as a significant regional player, with concentrated assets, infrastructure and exploration and development potential for future growth. It will add high-margin reserves and production, diversify our world-wide portfolio by adding strong assets in a stable jurisdiction, and complement the longer cycle-time projects we have in the Athabasca oil sands, offshore West Africa, and the deep-water Gulf of Mexico.

Our North Sea acquisition establishes us as a significant regional player.

Our UK strategy is focused on exploration and exploitation near existing infrastructure. We have a number of exploitation opportunities in our existing fields and smaller satellite discoveries close to infrastructure. Most of our unexplored acreage is near Scott/Telford or Buzzard, and could be tied-in quickly upon success.

The Scott field is subject to Petroleum Revenue Tax (PRT), although no PRT is payable until available oil allowances have been fully utilized. No PRT is expected to be payable before 2009. Once payable, PRT is levied at 50% of cash flow after capital expenditures, operating costs and an oil allowance. PRT is applicable to fields receiving development consent prior to March 1993, thereby excluding both the Buzzard and Telford fields. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate is 30% of taxable income. Income from oil and gas activities is also subject to a supplemental charge of 10%. Assuming WTI of US$30/bbl, we do not expect to pay current taxes until 2009. The amount and timing of income taxes payable depends on many factors including price, production and capital investment levels.

Our share of royalty-free Buzzard production is expected to climb to 80,000 boe/d in 2007.

BUZZARD

Buzzard is one of the largest discoveries in the UK North Sea in recent years. Discovered in 2001, it is in the Outer Moray Firth, central North Sea, approximately 100 km northeast of Aberdeen, in 100 metres of water.

Our Buzzard development involves contractors across Europe building a three bridge-linked platform complex comprising wellhead, production and utilities decks and topsides. The facilities will have capacities of 200,000 bbls/d of oil and 60 mmcf/d of gas. Currently, we anticipate the field will produce through 27 production wells, eight pre-drilled and producing by late-2006. Reservoir pressure will be maintained through an active water-flood program. We estimate peak gross production rates in 2007 at 180,000 bbls/d of oil and approximately 30 mmcf/d of gas, with our share at 80,000 boe/d before royalties.

Work is well underway to construct jackets and topsides that will form the Buzzard platform installation. At year-end 2004, the development project was over 50% complete, on schedule and on budget. In 2005, we plan to invest $530 million to transport the three jackets to Buzzard, install them, install the wellhead topsides, initiate drilling of the production wells, and install the gas and oil export pipelines. In summer 2006, we plan to install the utilities and production topsides and initiate hook-up and project commissioning.

Oil from Buzzard will be exported via the Forties Pipeline System to the Grangemouth, Scotland refinery. Gas will be exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland.

SCOTT / TELFORD

Scott and Telford are both producing fields with additional exploitation opportunities. Scott was discovered in 1987 and began producing in September 1993. Telford was discovered in 1991 and came on stream in 1996. Oil accounts for over 85% of production at Scott and around 50% at Telford.

Oil and gas is produced through numerous subsea wells and from wells drilled from the Scott platform. Oil is delivered to the Grangemouth, Scotland refinery via the Forties pipeline. Gas is exported via the SAGE pipeline to a terminal at St. Fergus in northeast Scotland.

In 2005, we plan to invest approximately $50 million to drill, complete, and tie-in five development wells, work-over several existing wells, and de-bottleneck and upgrade facilities on the Scott platform.

We have a number of smaller discoveries near Scott, Buzzard or third-party facilities.

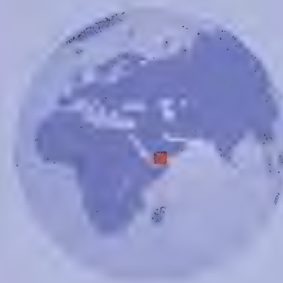
OTHER

We have a number of smaller discoveries on operated blocks near Scott, Buzzard or third-party facilities. Ettrick could be developed using a floating production facility, or tied-in to Buzzard (20 km away) once excess capacity is available. Exploitation projects near Scott such as Perth, Black Horse and Bugle are in various stages of evaluation. Farragon should begin producing in late-2005, with our 20%, non-operated share of production expected to reach between 3,000 and 4,000 boe/d before royalties in early 2006.

In 2005, we plan to drill at least four exploration wells and most are close to Scott/Telford or Buzzard.

Middle East—Yemen

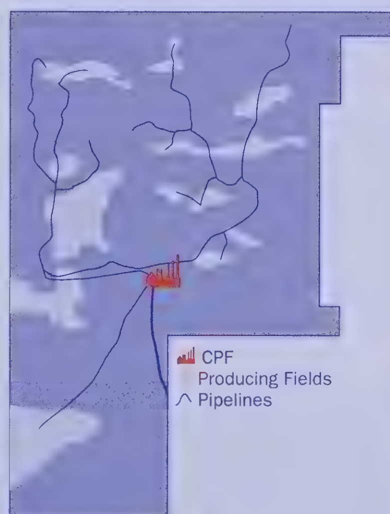
Yemen has been Nexen's most significant international region since first production on the Masila Block in 1993. We operate the country's largest oil project and have developed excellent relationships with the government and communities near our operations. Our success and reputation in Yemen opens doors elsewhere in the Middle East and around the world.



Our strategy here is to maximize value from our existing blocks while continuing to search for new fields in deeper horizons. We have two producing blocks: Masila (Block 14) and East Al Hajr (Block 51). In 2004, we produced 107,300 bbls/d before royalties (53,500 after royalties) of oil, representing approximately 30% of 2004 cash flow. Proved reserves of 80 mmboe (133 before royalties) comprise approximately 18% of Nexen's total proved oil and gas reserves after royalties.

MASILA BLOCK (BLOCK 14)

We have a 52% working interest in and operate the Masila Project. Our share of 2004 production was 106,200 bbls/d before royalties (52,500 after royalties). After more than 10 years of growth, our Masila fields have started maturing, but significant value still remains. Due to terms in the production sharing agreement, we still expect to generate approximately 40% of the total project cash flow from the remaining 20% of reserves.



We expect to generate approximately 40% of the total project cash flow from the remaining 20% of the reserves.

The first successful Masila exploratory well was drilled at Sunah in 1991, with additional discoveries quickly following at Heijah and Camaal. Initial production began in July 1993 with the first lifting of oil in August 1993. Masila Blend oil averages 31° API at very low gas-oil ratios. Most of the oil is produced from the Upper Qishn formation, but we also produce from deeper formations including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand, and basement formations.

We are managing our drilling pace to ensure we recover the remaining reserves in the most efficient, cost-effective manner. We still see 150 drillable locations and plan to drill 20 to 40 wells annually. In 2005, we plan to invest approximately $70 million to drill at least 20 wells and test deeper horizons where we have had recent success.

Masila is the largest oil project in Yemen. Each day, approximately 1.9 million barrels of fluid are produced and collected at our Central Processing Facility (CPF) through over 1,000 km of gathering lines. Water is separated at the field or CPF and re-injected via water disposal wells in an environmentally sensitive manner.

Masila is the largest oil project in Yemen.

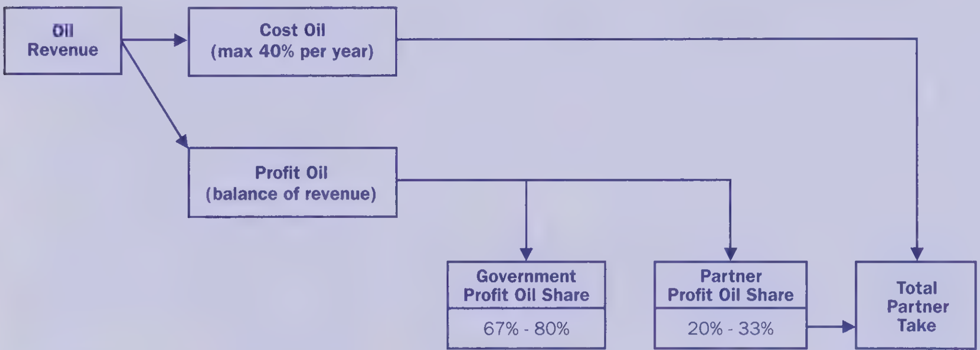
Treated oil is pumped from the CPF via 138 km of pipeline to the export terminal at Ash-Shihr. This pipeline ships Masila, East Al Hajr and third-party crude. Oil is stored in one of six tanks (one 1,000,000 barrel tank and five 500,000 barrel tanks). From the tanks, oil travels through a subsea pipeline to a pipeline end manifold (PLEM) 4 km offshore in 50 metres of water. The oil moves through the PLEM up to a single point mooring buoy at the water surface and then through two floating pipelines into tankers.

The oil is shipped to primary customers in Asia. Masila Blend crude oil enjoys a strong market due to its quality, reliability of supply and a consolidated marketing approach. During 2004, we sold our Masila crude oil at an average discount of US$4.84/bbl to WTI.

Masila production is governed by a Production Sharing Agreement (PSA) signed in 1987 between the Government of Yemen and the Masila joint venture partners (Partners), including Nexen. Under the PSA, we have the right to produce oil from Masila into 2011 and to negotiate a five-year extension. Production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all exploration, development, and operating costs which are funded by the Partners. Costs are recovered from a maximum of 40% of production each year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for 4 years
Development	16.7% per year for 6 years

The remaining production is profit oil shared between the Partners and the Government and is calculated on a sliding scale based on production. The Partners' share of profit oil ranges from 20 to 33%. The structure of the agreement moderates impact on the Partners' cash flows during periods of low prices. We recover our costs first, and then share any remaining profit oil with the Government. At current production levels, the Government is entitled to approximately 74% of the profit oil, which includes a component for Yemen income taxes payable by the Partners at 35%. In 2004, the Partners' share of Masila production, including recovery of past costs, was approximately 38%.



EAST AL HAJR BLOCK (BLOCK 51)

Full production from Block 51 is expected to grow to 25,000 bbls/d before royalties in mid-2005.

We have an 87.5% working interest in and operate East Al Hajr. The first successful exploratory well was drilled at BAK-A in 2003, with the BAK-B discovery quickly following. Early production began in November 2004 and the field was producing 16,700 bbls/d before royalties at year-end. Full production is expected to grow to 25,000 bbls/d before royalties in mid-2005.

Development of the BAK-A discovery began in 2004, and will initially include 16 wells, a central processing facility, a gathering system and a 22-km tieback to our Masila export pipeline. Additional development wells are planned throughout 2005. The BAK-B field will initially be developed with seven wells and will come on stream in late-2005.

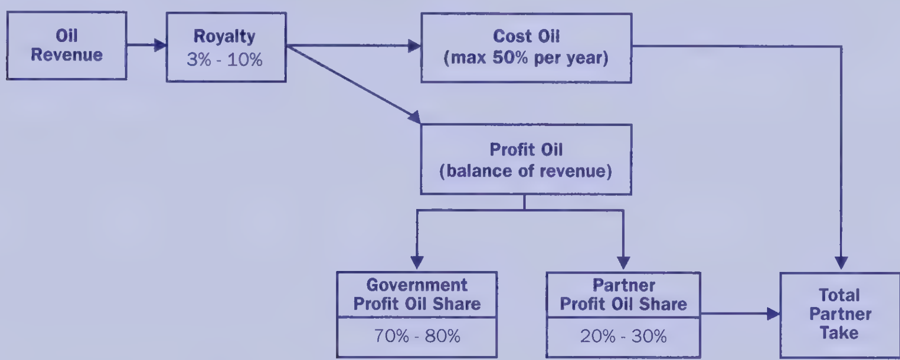
In 2004, we drilled four exploration wells on the block. The first two wells were abandoned. The third well, BAK-I, encountered oil shows and will be production tested in early 2005 after we source the necessary testing equipment. The fourth exploration well, BAK-J, was suspended after encountering oil and gas shows associated with high formation pressures, and will be re-entered and deepened when suitable equipment is located and high-pressure drilling equipment is sourced.

In 2005, we plan to invest approximately $200 million to complete development of the BAK-A and BAK-B fields and continue exploring the block with four exploration wells.

This block is governed by a PSA between the Government of Yemen, and the Partners: The Yemen Company (an entity owned by the Government of Yemen) (12.5% interest) and Nexen (87.5% interest). The PSA expires in 2023 and we have the right to negotiate a five-year extension. Under the terms of the PSA, the Partners pay a royalty ranging from 3 to 10% to the Government depending on production. The remaining production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the project's exploration, development and operating costs, funded solely by Nexen. Costs are recovered from a maximum of 50% of production each year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	75% per year, declining balance
Development	75% per year, declining balance

The remaining production is profit oil that is shared between the Partners and the Government on a sliding scale based on production rates. The Partners' share of profit oil ranges from 20% to 30%. The Government's share of profit oil includes a component for Yemen income taxes payable by the Partners at a rate of 35%.



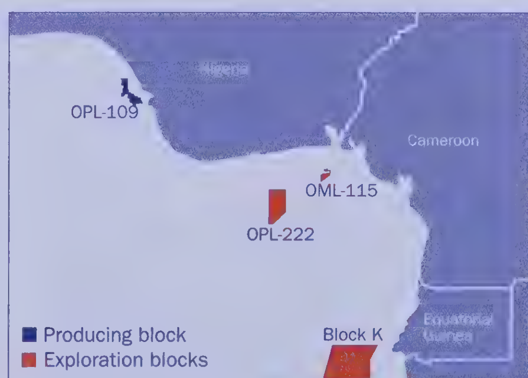
OTHER EXPLORATION BLOCKS

In 2004, we relinquished our interest in exploration Blocks 11, 12, 36, 50, 54, and 59.

Offshore West Africa

Offshore West Africa is a growing core area where we already have discoveries. It offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. Our strategy here is to explore and develop our portfolio for medium- to long-term growth. We have three exploration projects underway—OPL-222 and OML-115, offshore Nigeria and Block K, offshore Equatorial Guinea. We are also producing our final barrels from our Ejulebe field, offshore Nigeria.

In 2004, we invested $69 million of capital offshore West Africa, and expect to invest $84 million in 2005.



Offshore West Africa is a growing core area where we already have discoveries.

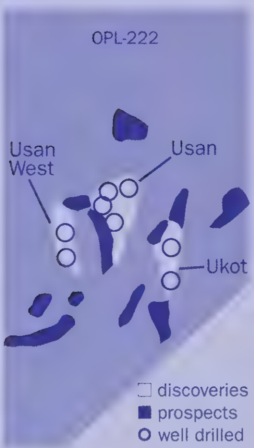
NIGERIA

Block OML-109—Ejulebe

Ejulebe is located in 45 feet of water on Block OML-109 in the Niger Delta, approximately 15 km offshore Nigeria. Crude oil production is transported through a pipeline to a third-party owned FPSO (floating production storage and off-loading vessel) where it is made available for sale and export. We operate the block under a risk service contract, requiring us to provide exploration, development and operatorship services and fund all costs in return for a service fee payable out of production from the block.

Ejulebe was still producing at year-end 2004. We expect to sell or abandon it in 2005. Abandonment would begin once government approvals have been obtained. No capital expenditures are proposed for 2005 other than abandonment expenditures.

We have confirmed the presence of commercial quantities of oil on OPL-222.



Block OPL-222

In 1998, we acquired a 20% non-operated interest in Block OPL-222, which includes 448,000 acres and is approximately 50 miles offshore in water depths ranging from 600 to 3,500 feet. The ongoing appraisal of the block indicates significant hydrocarbon accumulations based on the drilling results outlined below:

Year	Well	Location	Results
1998	Ukot-1	Ukot field discovery well	encountered three oil-bearing intervals and flowed at restricted rate of 13,900 bbls/d from two intervals
2002	Usan-1	Usan field discovery well	encountered several oil-bearing intervals and flowed at restricted rate of 5,000 bbls/d from one interval
2003	Usan-2	3 km west of discovery	appraised up-dip portion of the fault block
2003	Usan-3	2 km northwest of discovery	appraised separate fault block and flowed at restricted rate of 5,600 bbls/d from one interval
2003	Ukot-2	3.5 km south of discovery	encountered three oil-bearing intervals
2003	Usan-4	5 km south of discovery	flowed at restricted rate of 4,400 bbls/d from first interval and 6,300 bbls/d from second interval
2004	Usan-5	6 km west of discovery	sampled oil in several intervals
2004	Usan-6	4 km south of Usan-5	flowed at restricted rate of 5,800 bbls/d from one interval

Usan-4 confirmed the presence of commercial quantities of crude oil and Usan-5 and Usan-6 have built on this to the west. The operator has applied to convert the block's licence to one or more Oil Mining Leases, which give 20 years to appraise, develop and produce the reserves. A field development plan for Usan is being prepared for submission to the government.

We plan additional exploration drilling on OPL-222 in 2005, and are now determining which prospects will be drilled.

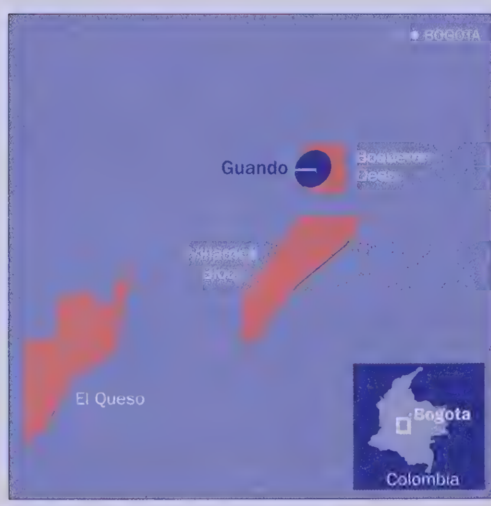
Block OML-115

The Nigerian Government formally approved the Deed of Assignment for OML-115 in December 2003, which assigned us a 40% interest in the block. Under the terms of our Joint Operating Agreement with Oriental Energy Resources Limited, we have a 100% paying interest and are entitled to between 90% and 95% of the revenues for an initial ten-year period. In 2004, we drilled a well on the Ameena prospect and did not find hydrocarbons. We expect to drill our next exploration well on the block in the first half of 2005.

EQUATORIAL GUINEA—BLOCK K

In 2003, we acquired a 25% operated interest in Block K, a deep-water block located 100 km offshore Equatorial Guinea. This interest was later increased to 50%. In 2004, we drilled a well on the Zorro prospect and found non-commercial quantities of hydrocarbons. We expect to drill our next exploration well on the block in the first half of 2005. We plan to meet all of the work commitments under the production sharing contract before the initial exploration period ends on June 1, 2005.

Other International



Boqueron Block including Guando field
Exploration blocks

COLOMBIA

Boqueron Block—Guando

In 2000, we made our first discovery at Guando on our 20% non-operated Boqueron Block. Boqueron is located in the Upper Magdalena Basin of central Colombia, approximately 45 km southwest of Bogota. Our share of 2004 production averaged 4,800 bbls/d before royalties (4,400 after royalties), about 2% of Nexen's total production.

Production from Guando is subject to a 5% to 25% royalty depending on daily production levels. The corporate income tax rate is 38.5%.

Exploration Blocks

Exploration activities in Colombia are focused on assessing potential drilling opportunities on captured blocks. In addition to Boqueron, we have interests in three exploration blocks in the Upper Magdalena Basin. Villarrica was acquired in 2000, El Queso in 2003 and Boqueron Deep in 2003.

Block	Interest (%)	Operator Status	2004 Activity
Boqueron Deep	40	non-operated	shot 80 km of seismic
Villarrica	50	operated	received environmental license for possible 2005 exploration well
El Queso	50	operated	shot 70 km of seismic

The fiscal policy structure in Colombia was revised in 2004 to make the terms more competitive in the world market. In December 2004, El Queso was recognized under the new terms. The exploration commitments have been completed for the current phase of Villarrica. The seismic acquisition with Phase One at Boqueron Deep is complete, with processing and interpretation activities carrying forward in 2005. The Phase Two commitments at El Queso will be fulfilled in 2005 with the budgeted seismic program.

In 2005, we plan to drill one exploration well and acquire additional seismic information to help identify future drilling opportunities.

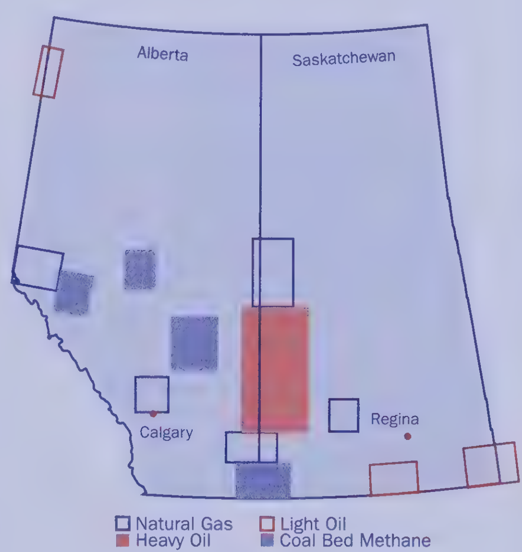
AUSTRALIA—BUFFALO

Since first production in 1999, the Buffalo field, offshore northwest Australia, has produced 53° API crude oil using a fixed wellhead platform linked to a leased floating production storage and offloading vessel.

We produced our final barrel of crude oil in late-2004, and averaged 2,700 bbls/d before royalties of oil for 2004. Field abandonment began in November 2004 and is expected to be completed in 2005. There were no capital expenditures in 2004, and other than abandonment expenditures, no further expenditures are expected in 2005.

Western Canada

Our strategy in Canada is to maximize value from our core operations while we actively pursue emerging sources of supply. We continue to manage our mature conventional assets through selective development, cost control and asset dispositions. In 2004, we produced 59,900 boe/d before royalties (47,000 after royalties) from these assets, which was approximately 24% of Nexen's total production. At year-end 2004, proved reserves of 141 mmboe (164 before royalties) were approximately 31% of Nexen's total proved oil and gas reserves after royalties.



Our Canadian operations are concentrated in geographical regions based on commodity:

- light oil—in southeast Saskatchewan and northeast British Columbia;
- heavy oil—in west central Saskatchewan;
- natural gas—near Calgary, in northern Alberta foothills, southeast Alberta and Saskatchewan.

We operate most of our producing properties and hold 1.7 million net acres of undeveloped land across Western Canada.

The core assets provide predictable production and earnings while we advance initiatives for future growth:

- coal bed methane (CBM)—focusing on Upper Mannville and Horseshoe Canyon coals and applying our experience in shallow gas drilling and water handling techniques
- enhanced oil recovery (EOR)—actively testing enhanced oil recovery technologies to increase recovery in our heavy oil fields.

Our Western Canadian strategy is to maximize value from core operations while pursuing emerging sources of supply.

Our Western Canadian production is split: 20% light oil, 40% heavy oil and 40% natural gas.

In 2004, we invested $175 million in Canada, with $148 million in our maturing core assets. In 2005, we plan to invest approximately $200 million, with $140 million allocated to our maturing core assets. From 2003 to 2005, we will have doubled our capital investment in CBM and EOR.

In Canada, the federal and provincial governments impose royalties on production at varying rates, ranging between 15% and 40%, from lands where they own the mineral rights. Some provinces also impose taxes on production from lands where they do not own the mineral rights. The Saskatchewan government assesses a resource surcharge on gross Saskatchewan resource sales of 3.6% that is reduced to 2.0% if the well was completed after October 1, 2002.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In 2003, legislation was introduced to reduce the federal corporate income tax rate on income from Canadian oil and gas activities from 28% to 21% by 2007. Canadian entities are also subject to capital taxes.

LIGHT OIL

Approximately 20% of our Canadian production is light oil.

We continue to develop and exploit our Hay property in northeast British Columbia. We discovered Hay in 1997 and started producing in April 2000. Hay is entering the final stage of development, with our focus on maximizing its value and evaluating remaining reserve potential.

Our operations in southeast Saskatchewan are characterized by mature fields producing medium-depth light oil. In 2004, we drilled 24 gross wells (19 net) as part of our capital program. Our 2005 plans include ongoing exploitation of these fields.

HEAVY OIL

Approximately 40% of our Canadian production is heavy oil.

Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also yields a lower price relative to light oil, as a smaller percentage of high value petroleum products can be refined from heavy oil.

Our heavy oil operations are in west central Saskatchewan. To maximize heavy oil returns, it is important to manage finding, development and operating costs. Our large production base and existing infrastructure helps. In 2004, we drilled 63 gross wells (52 net) as part of our capital program. In 2005, we plan to continue exploiting our existing fields through drilling and optimizing operations.

NATURAL GAS

Approximately 40% of our Canadian production is natural gas, produced primarily from shallow sweet reservoirs in southeast Alberta, southwest and northwest Saskatchewan and from deep sour gas near Calgary and in the northern Alberta foothills.

Shallow gas is natural gas produced from thin, shallow sand formations yielding sweet, low-pressure gas. In general, shallower gas targets are cheaper to drill and develop, but have relatively smaller reserves and lower productivity per well. We have been producing sour natural gas from our Balzac field northeast of Calgary since 1961. This sour gas is processed through our operated Balzac plant. We also have natural gas production from our Findley properties in the Alberta foothills and gas production associated with oil wells. In 2005, we expect to drill 126 gross wells (117 net).

Limited gas exploration activity is focused in the foothills of Alberta and in Montana and central Saskatchewan.

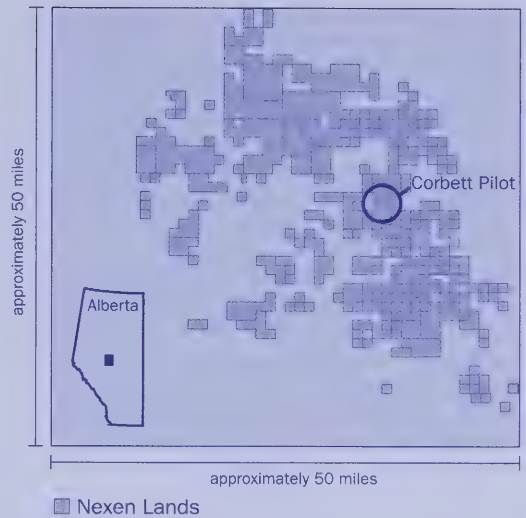
COAL BED METHANE (CBM)

CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by coal in coal deposits rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in reservoir pressure. If the coal deposit is water saturated, water generally needs to be extracted to reduce the pressure and allow gas production to occur. If the coal does not produce water and is "dry", gas will be produced from initial development. CBM fields are likely to require between two and eight gas wells per section to efficiently extract the natural gas. Regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain. Water producing CBM wells in the United States generally show increasing gas production rates for a period of approximately one to three years before gas rates begin to decline.

At the end of 2004, our net undeveloped CBM land position was 285,000 acres. Most of this land is in the Fort Assiniboine region of Alberta, where our Corbett pilot project is located. We have also established positions in other prospective CBM areas in Alberta.

Our CBM pilot at Corbett, operated by Trident Exploration, has established techniques to produce natural gas from the wet Upper Mannville coals. Commercial feasibility depends on achieving threshold production levels, which we hope to achieve in 2005. These coals are generally deeper than the Horseshoe Canyon "dry coal" play which is now being commercially developed in Alberta. During 2004, we expanded our Corbett pilot from 15 to 49 producing wells.

In 2005, besides the potential of initiating commercial development at Corbett, we will continue to evaluate other Mannville and Horseshoe Canyon CBM prospects and pursue new opportunities in CBM. Our capital expenditures in 2004 were approximately $30 million, and we plan to invest $45 million on CBM in 2005.



A strong land position is critical to a successful CBM strategy.

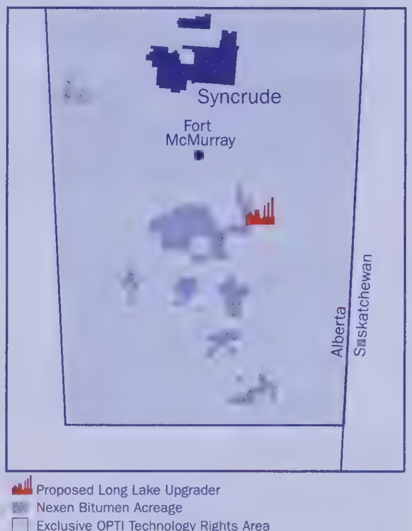
ENHANCED OIL RECOVERY (EOR)

Heavy oil reservoirs typically have lower recovery factors than conventional oil reservoirs, leaving substantial amounts of oil in the ground. This creates an opportunity to increase recovery factors by applying new technology. We are researching various technologies to enhance our heavy oil recovery with ongoing pilot projects in west central Saskatchewan.

Athabasca Oil Sands

Our oil sands strategy is to economically develop our bitumen resource to provide low-risk, stable, future growth. Our strategy involves integrating bitumen production with field upgrading technology to produce a premium synthetic crude oil. Our oil sands strategy also includes our 7.23% investment in the Syncrude oil sands mining operation.

In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI Canada) to develop the Long Lake property (Lease 27) using steam-assisted-gravity-drainage (SAGD) for bitumen production and field upgrading with the OrCrude™ process, a technology to which OPTI Canada has the exclusive Canadian license. OPTI Canada has since reorganized its interest into OPTI Long Lake L.P. (OPTI). We also acquired from OPTI the exclusive right to use the technology within approximately 100 miles of Long Lake in collaboration with OPTI, and the right to use the technology independently elsewhere in the world.



We have 199,000 net acres of bitumen-prone lands located in the Athabasca oil sands of northeast Alberta, and plan to continue acquiring more. We plan to develop our bitumen lands in a phased manner using our integrated upgrading strategy. To begin exploiting this resource, we sanctioned and began development of our Long Lake Project in 2004.

We continue to expand our bitumen holdings and plan to develop them in a phased manner using our integrated upgrading strategy.

In 1995, Alberta announced generic royalty terms for new oil sands projects that provide for a royalty rate of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. We expect to be subject to this royalty on our bitumen production and not our upgraded synthetic crude oil production.

LONG LAKE PROJECT

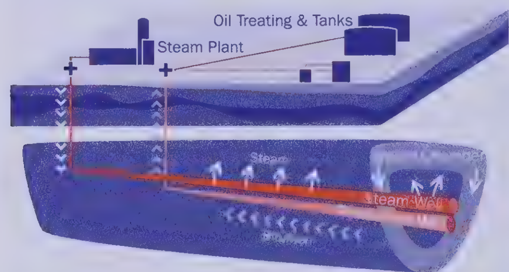
We expect our share of phase one production from Long Lake to be 30,000 bbls/d of premium synthetic crude.

Our $3.5 billion Long Lake Project, the fourth and next major integrated oil sands project in Canada, received regulatory approval in 2003. The project consists of approximately 72,000 bbls/d of SAGD bitumen production integrated with a field upgrading facility using the OrCrude™ process and commercially available hydrocracking and gasification. The project is expected to produce approximately 60,000 bbls/d of premium synthetic crude oil with low sulphur content once the upgrader is on stream in the second half of 2007. The project is designed to generate its own fuel and electricity, resulting in significant operating cost savings compared to other bitumen production and upgrading projects and significantly lower price risk on input costs. By upgrading the bitumen to synthetic crude oil, we should also avoid price risk on the production. We are the operator of the Long Lake lease and are responsible for construction, development and operation of the SAGD project, while OPTI is responsible for the design, construction and operation of the upgrader. We will share the production and operating costs of the project equally with OPTI.

The SAGD and upgrader integration, along with the proprietary processes, allows us to overcome three main economic hurdles of SAGD bitumen production: 1) cost of natural gas, 2) cost of diluent, and 3) the realized price of bitumen. The project generates synthetic gas from internally produced asphaltenes for use as fuel. This essentially eliminates the need for purchasing natural gas. With the upgrading facilities located on site, expensive diluent is not required to transport the produced bitumen to market. Upgrading the bitumen into a highly desirable refinery feedstock or diluent supply enables the end product to command significantly higher prices than raw bitumen.

We plan to produce bitumen using SAGD, a proven technology now being commercialized at several locations in the region.

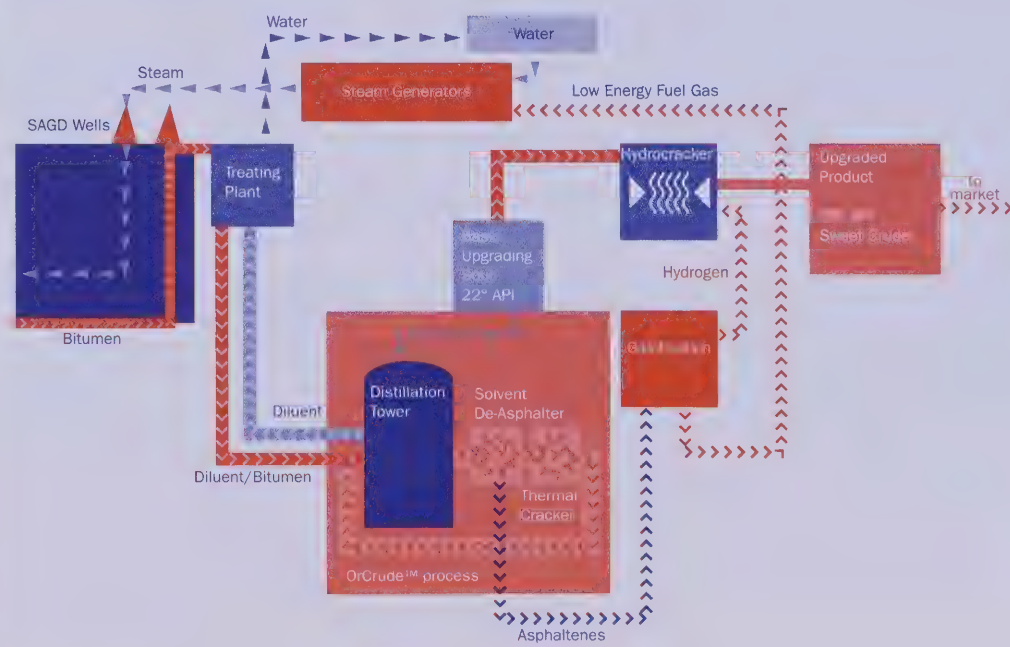
SAGD Production



SAGD involves drilling two parallel horizontal wells, generally between 2,300 and 3,300 feet in length with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. To optimize the project's well design, a three-well pair SAGD pilot was completed and is still operating. We also have interests in other SAGD projects at various stages of assessment outside of Long Lake.

SAGD and Upgrader Integration

Our SAGD and upgrader integration allows us to limit our exposure to critical variables affecting the economics of SAGD bitumen production: 1) cost of natural gas, 2) cost of diluent, and 3) price of bitumen.



The OrCrude™ technology, using distallation, solvent de-asphalting and thermal cracking, converts bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude is upgraded to light (39° API) premium synthetic crude oil and the asphaltenes are converted to a low-energy, synthetic fuel gas containing free hydrogen for use in the upgrading process. The synthetic fuel will be burned in a co-generation plant to produce steam for the SAGD operations and for on-site power. A 500-bbl/d demonstration plant successfully separated asphaltenes and upgraded over 250,000 bbls of various types of bitumen from the Cold Lake and Athabasca regions, including Long Lake bitumen. Combined SAGD, cogeneration, and upgrading operating costs are expected to average between $7 and $9/bbl.

Combined SAGD, cogeneration and upgrading costs are expected to average between $7 and $9/bbl.

On February 12, 2004, our Board of Directors approved proceeding with commercial development of the Long Lake Project. Field construction work on the SAGD and upgrader facilities began in 2004, with above ground construction scheduled to begin in the first half of 2005. Commercial SAGD drilling of 78 well pairs began in September 2004, with expected completion by early 2006. At year-end, procurement of major equipment was substantially complete, with pricing as budgeted. First steam injection is scheduled to commence in 2006 and the upgrader is scheduled to start-up in the second half of 2007. We expect peak gross production to reach around 60,000 bbls/d before royalties of synthetic crude oil. We expect to maintain this rate over the project's life, estimated at 40 years, by periodically drilling additional SAGD well pairs.

We expect the gross capital cost for the Long Lake Project, including upgrader commissioning and start-up to total $3.5 billion ($1.75 billion, net to us). This is $98 million higher ($49 million, net to us) than the estimate at the time of sanctioning as we have accelerated the drilling of 13 well pairs to ensure we have sufficient bitumen supply to fill the upgrader. In 2004, we invested approximately $362 million and expect to invest $765 million in 2005. The spending in 2005 increases substantially because we are entering the construction phase of the commercial facilities. Ongoing sustaining capital is expected to average $2.50/bbl. We estimate the capital costs of producing and upgrading bitumen using this technology will be comparable to those for surface mining and coking upgrading on a barrel of daily production basis.

Our share of Long Lake capital costs to upgrader start-up is estimated at $1.75 billion.

Reserves, Production and Related Information

In addition to the tables below, we refer you to the Supplementary Data in Item 8 of this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Net Sales by Product from Continuing Operations (including Syncrude)

(Cdn$ millions)	2004	2003	2002
Conventional Crude Oil and Natural Gas Liquids	1,856	1, 590	1,374
Synthetic Crude Oil	321	240	245
Natural Gas	607	618	345
	2,784	**2,448**	**1,964**

Crude oil (including synthetic crude oil) and natural gas liquids represent approximately 78% of our net sales, while natural gas represents the remaining 22%.

Sales Prices and Production Costs (excluding Syncrude)

	Average Sales Price[1]			Average Production Costs[1]		
	2004	2003	2002	2004	2003	2002
Crude Oil and NGLs (Cdn$/bbl)						
Yemen	47.59	39.45	38.80	5.64	4.37	4.13
Canada[2]	36.60	32.37	31.13	11.76	10.00	8.98
United States	46.60	37.68	38.88	6.09	5.08	10.95
Australia[2]	51.22	43.14	40.30	35.73	20.21	12.14
United Kingdom	46.81	-	-	8.26	-	-
Other Countries	43.07	38.22	38.96	4.09	9.01	10.69
Natural Gas (Cdn$/mcf)						
Canada[2]	5.76	5.64	3.57	0.85	0.65	0.70
United States	7.89	8.16	5.29	1.02	0.89	1.83
United Kingdom	8.28	-	-	-	-	-

Notes:
1 Prices and unit production costs are calculated using our working interest production after royalties.
2 Includes results of discontinued operations. (See Note 11 to our Consolidated Financial Statements.)

Producing Oil and Gas Wells

	2004					
	Oil		Gas		Total	
(number of wells)	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
United States	196	89	208	129	404	218
Yemen	371	195	-	-	371	195
United Kingdom	27	12	-	-	27	12
Canada	2,831	2,041	2,536	2,201	5,367	4,242
Nigeria	1	1	-	-	1	1
Colombia	74	16	-	-	74	16
Total	**3,500**	**2,354**	**2,744**	**2,330**	**6,244**	**4,684**

Notes:
1 Gross wells are the total number of wells in which we own an interest.
2 Net wells are the sum of fractional interests owned in gross wells.

Oil and Gas Acreage

	2004					
	Developed		Undeveloped[1]		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States	182	102	1,020	494	1,202	596
Yemen[2]	45	24	761	633	806	657
Nigeria[2, 3, 4]	1	1	524	128	525	129
Equatorial Guinea	–	–	1,106	553	1,106	553
Canada	909	695	2,754	1,680	3,663	2,375
Colombia[5]	1	–	787	552	788	552
United Kingdom	44	19	1,598	708	1,642	727
Australia	1	1	–	–	1	1
Total	**1,183**	**842**	**8,550**	**4,748**	**9,733**	**5,590**

Notes:
1 Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.
2 The acreage is covered by production sharing contracts.
3 The acreage is covered by a risk service contract.
4 The acreage is covered by a joint venture agreement.
5 The acreage is covered by an association contract.

Drilling Activity

	2004						
	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United States	0.3	1.8	2.1	11.0	1.0	12.0	14.1
United Kingdom	-	-	-	-	-	-	-
Yemen	-	2.0	2.0	37.3	0.5	37.8	39.8
Nigeria	0.4	1.0	1.4	-	-	-	1.4
Canada	13.4	1.0	14.4	202.9	-	202.9	217.3
Colombia	-	-	-	7.0	-	7.0	7.0
Equatorial Guinea	-	0.5	0.5	-	-	-	0.5
Total	**14.1**	**6.3**	**20.4**	**258.2**	**1.5**	**259.7**	**280.1**

	2003						
	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United States	-	0.5	0.5	8.3	0.1	8.4	8.9
Yemen	8.0	1.0	9.0	49.0	-	49.0	58.0
Nigeria	0.6	-	0.6	-	-	-	0.6
Canada	15.4	1.7	17.1	157.7	2.5	160.2	177.3
Colombia	-	1.0	1.0	6.2	-	6.2	7.2
Brazil	-	0.2	0.2	-	-	-	0.2
Total	**24.0**	**4.4**	**28.4**	**221.2**	**2.6**	**223.8**	**252.2**

2002	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United States	-	1.4	1.4	14.9	0.6	15.5	16.9
Yemen	-	0.6	0.6	38.0	1.0	39.0	39.6
Canada	16.0	4.0	20.0	225.0	8.0	233.0	253.0
Australia	-	-	-	2.0	-	2.0	2.0
Other Countries[1]	0.2	0.7	0.9	2.0	0.2	2.2	3.1
Total	**16.2**	**6.7**	**22.9**	**281.9**	**9.8**	**291.7**	**314.6**

Note:
1 Other countries include drilling primarily in Nigeria, Colombia and Brazil.

WELLS IN PROGRESS

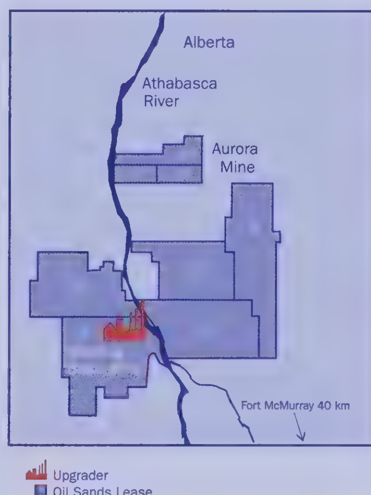
At December 31, 2004, we were in the process of drilling ten wells (5.7 net) in the United States, 29 wells (15.5 net) in Canada, four wells in Yemen (3.0 net), and one well in Colombia (0.2 net).

Syncrude Mining Operations

We hold a 7.23% participating interest in Syncrude Canada Ltd. (Syncrude). This joint venture was established in 1975 to mine shallow oil sands deposits using open-pit mining methods, extract the bitumen from the oil sands, and upgrade the bitumen to produce a high-quality, light (32° API), sweet, synthetic crude oil.

The Syncrude operation exploits a portion of the Athabasca oil sands deposit which contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of over-burden, have bitumen grades ranging from 4 to 14 weight percent, and ore bearing sand thickness of 100 to 160 feet.

Syncrude's operations are located on eight leases (10, 12, 17, 22, 29, 30, 31, and 34) covering 258,000 acres, 40 km north of Fort McMurray in northeast Alberta.



Syncrude mines oil sands at three mines: Base, North, and Aurora North. These locations are readily accessible by public road. At the Base Mine (lease 17), a dragline, bucket wheel reclaimers, and belt conveyors are used for mining and transporting oil sands. In the North Mine (leases 17 and 22) and in the Aurora North Mine (leases 10, 12, and 34), a truck-and-shovel and hydro-transport system is used.

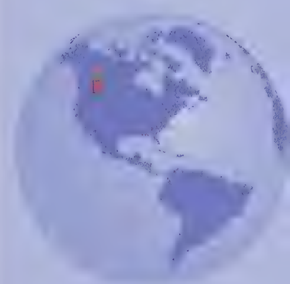
The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 240 million tons of oil sands per year and about 110 mmbbls of bitumen per year. To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Base Mine uses hot water, steam, and caustic soda to create a slurry, while at the North Mine and the Aurora North Mine the oil sands are mixed with warm water to produce a slurry.

The extracted bitumen is fed into a vacuum distillation tower and two cokers for primary upgrading. The resulting products are then separated into naphtha, light gas oil, and heavy gas oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities to form light, sweet synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale. In 2004, the upgrading process yielded 0.86 barrels of synthetic crude oil per barrel of bitumen.

The quality of Syncrude's synthetic crude oil typically allows it to be sold at a premium to WTI. In 2004, about 45% of the synthetic crude oil was sold to Edmonton area refineries and the remaining 55% was sold to refineries in eastern Canada and the mid-western United States.

Electricity is provided to Syncrude from two generating plants: a 270 MW plant and an 80 MW plant. Both plants are located at Syncrude and are owned by the Syncrude participants.

Since operations started in 1978, Syncrude has shipped more than 1.5 billion barrels of synthetic crude oil to Edmonton, Alberta by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 to accommodate increased Syncrude production.



The quality of Syncrude's synthetic crude oil typically allows it to be sold at a premium to WTI.

To the end of 2004, our total investment in the property, plant and equipment, including surface mining facilities, transportation equipment, and upgrading facilities is approximately $1 billion. Based on development plans, our share of future expansion and equipment replacement costs over the next 35 years is expected to be about $1.3 billion.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating license for the eight oil sands leases through to 2035. The licence permits Syncrude to mine oil sands and produce synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start-up of operations in 1978.

Syncrude pays a royalty to the Province of Alberta. Subsequent to 1987, this royalty was equal to 50% of Syncrude's deemed net profits after deduction of capital expenditures. In 1995, the Province announced generic royalty terms for new oil sands projects that provide for a royalty rate of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. In 1997, the Province of Alberta and the Syncrude owners agreed to move to the generic royalty terms when the total of all allowed capital costs incurred after December 31, 1995 equalled $2.8 billion (gross). That total was surpassed at the end of 2001.

Syncrude's capacity expansion to 360,000 bbls/d should be complete in 2006.

In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude had increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine which involved extending mining operations to a new location about 25 miles north of the main Syncrude site. In 2001, the Syncrude owners approved the third stage of the Syncrude expansion, which will increase capacity to 360,000 bbls/d in 2006. Due to higher engineering, manufacturing, and construction costs, the estimated costs of the Stage 3 expansion have increased from initial estimates of $4.1 billion to $7.8 billion. Nexen's share of the project costs was revised in May 2004 to $565 million, of which $440 million was incurred by year-end 2004. Activities in 2005 are focused on completing the upgrader expansion, as well as spending $415 million (Nexen's share is $30 million) to replace bitumen production capacity that will be lost with the closure of the depleted southwest quadrant of the Base Mine in early 2006.

In 2004, Syncrude's production of marketable synthetic crude oil was 238,000 bbls/d. Nexen's share was 17,200 bbls/d before royalties.

The following table sets out certain operating statistics for the Syncrude operations:

In 2004, approximately 1.8 tons of oil sands produced 1 barrel of bitumen that was upgraded into 0.86 barrels of synthetic crude oil.

	2004	2003	2002
Total mined volume[1]			
Millions of tons	389	380	375
Mined volume to oil sands ratio[1]	2.1	2.3	2.2
Oil sands processed			
Millions of tons	188	168	173
Average bitumen grade (weight %)	11.1	11.0	11.2
Bitumen in mined oil sands			
Millions of tons	21	18	19
Average extraction recovery (%)	87	89	90
Bitumen production[2]			
Millions of barrels	103	92	98
Average upgrading yield (%)	86	86	86
Gross synthetic crude oil shipped[3]			
Millions of barrels	87	77	84
Nexen's share of marketable crude oil			
Millions of barrels before royalties	6.3	5.6	6.1
Millions of barrels after royalties	6.1	5.5	6.0

Notes:

1 Includes pre-stripping of mine areas and reclamation volumes.

2 Bitumen production in barrels is equal to bitumen in mined oil sands multiplied by the average extraction recovery and the appropriate conversion factor.

3 Approximately 1.2% of the produced synthetic crude oil is used internally at Syncrude. The remaining synthetic oil is sold externally.

OIL AND GAS MARKETING

Our marketing group sells proprietary and third-party natural gas, crude oil and power in certain regional markets where we have built a solid physical asset base. This includes access to transportation, storage and facilities, as well as crude oil and natural gas we produce or acquire. We optimize the margin on our base business by trading around our access to these physical assets when market opportunities present themselves. We use financial and derivative contracts, including futures, forwards, swaps and options for hedging and for trading purposes.

Our marketing strategy is to:

- obtain competitive pricing on the sale of our own oil and gas production,
- provide market intelligence in support of our oil and gas operations,
- provide superior customer service to producers and consumers, and
- capitalize on market opportunities through low-risk trading based on our transportation and storage capacity.

This strategy aligns with our corporate focus to extract full value from our assets, and provides us with the market intelligence needed to deliver our current and future oil and gas production to market at competitive pricing.

GAS MARKETING

The marketing and trading of natural gas is our marketing division's largest revenue stream. We focus on key regional markets where we have a strategic presence—solid customer relationships, in-depth understanding of the market or established physical trading-based assets. We capture regional opportunities by managing supply, transportation and storage assets for producers and end users. In addition to the fee-for-service income we realize from managing these assets, we generate further net revenue by:

- capitalizing on location spreads (differences in prices between market locations) using our transportation assets, and
- capitalizing on time spreads (differences in price between summer and winter) using our storage assets.

We have offices in key regions including Calgary, Detroit and Houston. Our Calgary office provides a variety of services including supply, storage, and transportation management as well as netback pool arrangements and other customer services. Our customers include producers and consumers in Western Canada as well as consumers (including utilities) in Eastern Canada, the Northeastern United States and the US mid-continent. Our Detroit office works closely with Calgary to provide services to our customers. Our presence in Houston has established us in the Gulf Coast region where we have our own production.

We use our access to transportation and storage facilities to optimize returns for ourselves as well as our customers.

In 2004, we grew our asset base by acquiring physical gas purchase and sales contracts, as well as natural gas transportation capacity on favourable terms. This gave us access to new producer gas until 2008, as well as pipeline capacity and gas purchase and sales contracts to the end of 2004. The majority of these gas purchase and sales contracts have been renewed to the end of 2005. We also added storage capacity in key regional locations.

Our position as a physical marketer at multiple delivery points in key markets gives us the flexibility to capitalize on time and location spreads. With pipeline capacity, we can move gas from producing regions to take advantage of price differences. We can also use storage capacity to store less expensive summer gas in the ground until the winter heating season arrives.

In addition to transportation and storage assets, we hold financial contracts that allow us to capture profits around time and location spreads. The basis risk we assume on these contracts is based on solid fundamental analysis and in-depth knowledge of regional markets. The risk is managed proactively by our product group teams and monitored closely by our risk group, with regular reporting to management and the Board.

CRUDE OIL MARKETING

Our crude oil business focuses on marketing physical crude oil volumes to end use refiners. The crude oil group markets our own production and over 100,000 bbls/d of third-party field production to refiners from producing regions where we operate. In addition to physical marketing, we take advantage of quality differentials and time spreads.

Our North American operations focus on key regions supported by our offices in Calgary and Houston. In Western Canada, our producer services group concentrates on the procurement of a diversified supply base, while the trading team seeks to optimize the mix for sale to refiners. Traditionally, the

The marketing and trading of natural gas is our marketing division's largest revenue stream.

We use our access to transportation and storage facilities to optimize returns.

Chicago area has been the key market for Western Canadian crude. The recent growth in our deep-water Gulf of Mexico crude oil production has given us the opportunity to expand our presence in that market through our Houston office.

Our international marketing group focuses on the physical marketing of our Yemen crude oil.

Internationally, we focus on the physical marketing of our Yemen crude oil. In order to meet customer needs, we may occasionally market other regional crude types. In addition to our own crude, we market production for our partners and third parties in the Yemen region. By locating our international crude oil marketing office in Singapore, we are well positioned to serve both the producing region and the Asian refining market.

Our crude oil marketing group also holds financial contracts that allow us to capture trading profits around time, quality and location spreads. The basis risk assumed is, like gas marketing, based on solid fundamental analysis and proprietary knowledge of regional markets, and it is managed and monitored closely by our risk group.

POWER MARKETING

Our power marketing group is responsible for optimizing the use of our 100 MW gas-fired combined-cycle power generation facility at Balzac, Alberta and for marketing power to larger commercial, industrial and municipal clients within Alberta. Our Balzac facility began operations in 2001. We expect to increase our power generation capacity with a 170 MW co-generation facility at Long Lake in 2007, and through our 70 MW Soderglen wind power project in southern Alberta in 2006. We have a 50% interest in each project.

CHEMICALS

Our chemicals facilities are modern, reliable, and strategically located to capitalize on competitive power costs or transportation infrastructure.

We manufacture sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil. This production is sold in North and South America, with a small amount of sodium chlorate distributed in Asia. Our manufacturing facilities are modern, reliable, and strategically located to capitalize on competitive power costs or transportation infrastructure to minimize production and delivery costs. This enables us to have reliable supplies and low costs, key factors for marketing bleaching chemicals.

The bleaching chemicals we produce are subject to commodity pricing structures. Our strategy for adding value in this business focuses on:

- improving our cost position,
- maintaining our market share,
- building a strong, sustainable North American customer base, and
- capturing new offshore opportunities.

Since 1999, we have made significant investments to grow our capacity, expand internationally and lower our overall cost structure, allowing us to improve our position in the bleaching chemicals industry.

The primary raw materials required to produce sodium chlorate and chlor-alkali products are electricity, salt, and fresh water. Electricity is the single largest operational cost, making up more than half of our cash costs. Labour is also a significant component of our manufacturing costs. Approximately 50% of our workforce is unionized, with collective agreements in place at all of our unionized plants.

Average Annual Production Capacity	2004	2003	2002
Sodium Chlorate (short-tons)			
North America	446,617	432,812	500,650
Brazil	70,213	70,213	57,320
Total	**516,830**	**503,025**	**557,970**
Chlor-alkali (short-tons)			
North America	356,002	356,002	351,844
Brazil	109,430	109,430	97,462
Total	**465,432**	**465,432**	**449,306**

NORTH AMERICA

The North American pulp and paper industry consumes approximately 95% of local sodium chlorate production. We market our sodium chlorate production to numerous pulp and paper mills under multi-year contracts that contain price and volume provisions. Approximately 30% of this production is sold in Canada, 60% in the US, and the rest marketed offshore.

Our Brandon plant is the world's largest sodium chlorate plant and one of the lowest cost producers in North America.

We are the third largest manufacturer of sodium chlorate in North America with five Canadian facilities: Nanaimo, British Columbia; Bruderheim, Alberta; Brandon, Manitoba; Amherstburg, Ontario; and Beauharnois, Quebec.

In October 2004, we completed an expansion of our Brandon, Manitoba plant by increasing capacity 33% to 260,000 tonnes per year. This expansion replaced higher-cost capacity idled in 2002 at Taft, Louisiana. Brandon is currently the world's largest sodium chlorate facility, and has one of the lowest cost structures in the industry, significantly enhancing our competitive position in North America.

Our chlor-alkali facility at North Vancouver, British Columbia manufactures caustic soda, chlorine and muriatic acid. Almost all of our caustic soda is consumed by local pulp and paper mills, while our chlorine is sold to various customers in the polyvinyl chloride, water purification and petrochemicals industries, primarily in the United States.

BRAZIL

We entered Brazil in 1999 by acquiring a sodium chlorate plant and a chlor-alkali plant from Aracruz Cellulose S.A., the leading Brazil manufacturer of pulp. The majority of the production is sold to Aracruz under a long-term sales agreement that expires in 2024. This agreement has an initial six year take-or-pay component that ends in 2005. Most of the chlorine and about 20% of the sodium chlorate production is sold in the merchant market under shorter-term contractual arrangements. In 2002, we completed expanding both facilities to meet Aracruz's growing needs. Chlorate production capacity is now 70,213 short-tons per year and chlor-alkali capacity is 109,430 short-tons per year.

ADDITIONAL FACTORS AFFECTING BUSINESS

See Item 7 of this Form 10-K.

GOVERNMENT REGULATIONS

Our operations are subject to various levels of government controls and regulations in the countries in which we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, all of which are subject to change from time to time. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. However, we participate in many industry and professional associations and otherwise monitor the progress of proposed legislation and regulatory amendments.

ENVIRONMENTAL REGULATIONS

Our oil and gas and chemical operations are subject to government laws and regulations designed to protect and regulate the discharge of materials into the environment in the countries where we operate. We believe that our operations comply in all material respects with applicable environmental laws. To mitigate our exposure we apply industry standards, codes and best practices to meet or exceed these laws and regulations. From time to time, we may conduct activities in countries where environmental regulatory frameworks are in various stages of evolution. Where regulations are lacking, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

We have an active Safety, Environment and Social Responsibility group that are responsible for ensuring that our worldwide operations are conducted in a safe, ethical and socially responsible manner. We have developed policies for continuing compliance with environmental laws and regulations in the countries in which we operate.

ENVIRONMENTAL PROVISIONS AND EXPENDITURES

The ultimate financial impact of environmental laws and regulations is not clearly known nor can they be reasonably estimated as new standards continue to evolve in the countries in which we operate. We estimate our future environmental costs based on past experience and current regulations. At December 31, 2004, $468 million ($770 million, undiscounted) has been provided in our consolidated financial statements for asset retirement obligations relating to our oil and gas, Syncrude and chemicals facilities. During 2004, we increased our retirement obligations for future dismantlement and site restoration by $146 million primarily due to the acquisition of oil and gas properties in the North Sea.

During 2004, our capital expenditures for environmental-related matters, including environment control facilities, were approximately $31 million. Our operating expenditures for environmental-related matters were approximately $8 million. Environmental related and site restoration capital expenditures in 2005 are expected to be approximately $47 million, primarily from the remediation of our Australia and Nigeria oil producing areas.

EMPLOYEES

We had 3,247 employees on December 31, 2004.

See page 125 for details on our executive officers.

Information on our executive officers is presented in Item 10 of this report.

Item 3. Legal Proceedings

There are a number of lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect upon our consolidated financial position or results of operations. We believe we have made adequate provisions for such lawsuits and claims.

Certain of our US oil and gas operations have received, over the years, notices and demands from the United States Environmental Protection Agency, state environmental agencies, and certain third parties with respect to certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands, and suits have been received for certain sites related to historical operations and activities in the US for which, although no assurances can be made, we believe that certain assumption and indemnification agreements protect our US operations from any present or future material liabilities that may arise from these particular sites.

On June 25, 2003, a subsidiary of Occidental Petroleum Corporation (Occidental) initiated a request for arbitration at the International Court of Arbitration of the International Chamber of Commerce regarding an Area of Mutual Interest Agreement (Agreement) in the Republic of Yemen. Pursuant to the Agreement, if Nexen proposed to conduct petroleum development operations within two small areas of Block 51 in the Republic of Yemen (Heijah/Tawila Extension Lands), then we were to offer Occidental the right to acquire 50% of our interest in those areas. The Agreement expired on March 12, 2003, with Nexen not having proposed any such operations. Occidental seeks a claim for declaratory relief under the Agreement, claims compensation for breach of contract (50% of the net profits earned or to be earned from the Heijah/Tawila Extension Lands), plus interest and costs. Subsequent to the expiry of the Agreement, we commenced exploration activities within Block 51, including the Heijah/Tawila Extension Lands and, in December 2003, filed a notice of commercial discovery with the Yemen government. Given that the agreement expired without Nexen having proposed to conduct petroleum development operations, we believe Occidental's claim is without merit and we are vigorously defending our contractual rights.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of Nexen's security holders during the fourth quarter of 2004.

Item 5. Market for the Registrant's Common Shares and Related Stockholder Matters

Nexen's common shares are traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol NXY.

On December 31, 2004, there were 1,329 registered holders of common shares and 129,199,583 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings. During the year, we made no purchases of our own equity securities.

Symbol: NXY
Traded on the TSX and NYSE with 129.2 million common shares outstanding.

Trading Range of Nexen's Common Shares

($/share)	TSX (Cdn $) High	TSX (Cdn $) Low	NYSE (US $) High	NYSE (US $) Low
2004				
First Quarter	53.35	45.00	40.61	34.10
Second Quarter	56.50	46.80	42.29	34.49
Third Quarter	53.70	44.34	42.13	33.88
Fourth Quarter	58.66	48.17	46.56	39.20
2003				
First Quarter	34.85	29.30	22.55	19.89
Second Quarter	35.59	28.26	26.31	19.75
Third Quarter	39.68	33.02	29.00	24.03
Fourth Quarter	47.08	36.65	36.47	27.32

On the TSX in 2004, we traded from a low of $44.34 in Q3 to a high of $58.66 in Q4.

Quarterly Dividends on Common Shares

($/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2004	0.10	0.10	0.10	0.10
2003	0.075	0.075	0.075	0.10

We increased our quarterly dividend to $0.10/share in Q4 2003.

Payment date for dividends was the first day of the next quarter.

The Income Tax Act of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. In accordance with the Canada-US Tax Treaty, we have deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock where the withholding tax is 5%.

The Investment Canada Act requires that a "non-Canadian" (as defined) file notice with Investment Canada and obtain government approval prior to acquiring control of a "Canadian business" (as defined). Otherwise, there are no limitations, either under the laws of Canada or in Nexen's charter on the right of a non-Canadian to hold or vote Nexen's securities.

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. The Plan creates a right, which attaches to each present and future outstanding common share. Each right entitles the holder to acquire additional common shares during the term of the right. Prior to the separation date, the rights are not separable from the common shares and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our Board can defer the separation date.

The Plan creates a right, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), for each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. The Plan must be reapproved by shareholders on or before our annual general meeting in 2005 to remain effective past that date.

Item 6. Selected Financial Data

See page 108 for differences between Canadian & US GAAP.

Five-Year Summary of Selected Financial Data in Accordance with US GAAP

(Cdn$ millions)	2004	2003	2002	2001	2000
Results of Operations					
Net Sales[1]	3,176	2,844	2,341	2,356	2,425
Net Income from Continuing Operations	775	462	299	340	474
Basic Earnings per Common Share from Continuing Operations ($/share)	6.03	3.73	2.45	2.82	3.79
Diluted Earnings per Common Share from Continuing Operations ($/share)	5.95	3.70	2.41	2.78	3.74
Net Income	788	420	352	365	522
Basic Earnings per Common Share ($/share)	6.13	3.39	2.88	3.03	4.17
Diluted Earnings per Common Share ($/share)	6.05	3.36	2.84	2.99	4.12
Production Before Royalties (mboe/d)[2]	250	269	269	268	256
Production After Royalties (mboe/d)[2]	174	185	176	184	171
Financial Position					
Total Assets[2]	12,339	7,703	6,764	5,609	5,874
Long-Term Debt[3]	4,214	2,470	2,575	2,242	2,238
Shareholders' Equity	2,892	2,131	1,812	1,414	1,050
Capital Investment, including Acquisitions	4,264	1,432	1,545	1,325	841
Dividends per Common Share ($/share)[4]	0.40	0.325	0.30	0.30	0.30
Common Shares Outstanding (thousands)	129,200	125,606	122,966	121,202	119,855

Notes:

1 During 2003, we sold non-core conventional light oil assets in southeast Saskatchewan in Canada producing 9,000 bbls/d. In late 2004, we concluded production from our Buffalo field, offshore Australia as anticipated. The results of these operations have been shown as discontinued operations.

2 In 2003, production increased from our deep-water Aspen development in the Gulf of Mexico in the United States. In 2004, production declined from our maturing assets in Yemen at Masila, in Canada, and in the United States on the Gulf of Mexico Shelf. In late 2004, we acquired North Sea assets and commenced production from Block 51 in Yemen.

3 In December 2004, we drew US$1,500 million on unsecured acquisition credit facilities to finance the purchase of North Sea assets. The remainder of the purchase price was funded from cash on hand.

4 Quarterly dividends were increased to 10¢ per share in the fourth quarter of 2003.

md&a

Masila Block, Yemen

contents

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 19 to the Consolidated Financial Statements. The date of this discussion is February 7, 2005.

Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Our discussion and analysis of our oil and gas activities with respect to oil and gas volumes, reserves and related performance measures is presented on a working interest before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis in tabular format.

Note: Canadian investors should read the Special Note to Canadian Investors on page 72 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

EXECUTIVE SUMMARY OF 2004 RESULTS

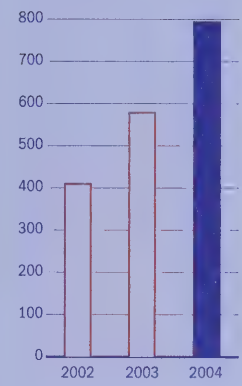
(Cdn$ millions)	2004	2003	2002
Net Income	793	578	409
Earnings per Common Share ($/share)	6.17	4.67	3.34
Cash Flow from Operating Activities	1,607	1,405	1,250
Production before Royalties (mboe/d)[1]	250	269	269
Production after Royalties (mboe/d)	174	185	176
Capital Investment, including Acquisitions	4,264	1,494	1,625
Net Debt[2]	4,219	1,690	2,527
Average Foreign Exchange Rate (Canadian to US dollar)	0.77	0.71	0.64

Notes:

1 Production before royalties reflects our working interest before royalties and includes production of synthetic crude oil from Syncrude. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

2 Long-term debt less net working capital.

Net Income
(Cdn$ millions)



In 2004, we had our best year ever financially. Strong oil and gas prices, outstanding results from marketing, and late-year production additions in Yemen and the North Sea fuelled our financial results. A stronger Canadian dollar, declining base production and increasing costs moderated these results. Nevertheless, net income has almost doubled since 2002. Over the same period, our average realized oil and gas price only increased 28%. This is, in part, the result of a strategic transition towards higher margin production, particularly in the deep-water Gulf of Mexico where we have added over 30,000 boe/d of low-royalty, low-cost production since 2002.

WTI averaged US$41.40/bbl in 2004, with crude oil prices spiking to new levels throughout the year. The gains made from high prices were partially offset by a strengthening Canadian dollar, relative to the US dollar. Our foreign revenues and realized commodity prices were impacted when translated into Canadian dollars, reducing cash flow from operating activities by $200 million and our net income by $105 million.

Record financial results were fuelled by strong prices, outstanding marketing results and new production from Yemen and the North Sea.

To a lesser extent, the strengthening dollar positively affected our results. Our foreign operating costs and capital expenditures were reduced when translated into Canadian dollars. Additionally, most of our debt is US dollar denominated, so the Canadian dollar debt equivalent was also decreased.

In total, we invested $4.3 billion in 2004 and made significant progress on the many longer cycle-time development projects in our portfolio. In the Athabasca oil sands, the Syncrude Stage 3 expansion is on schedule for production start-up in mid-2006 and our Long Lake Project is on budget and on schedule to commence bitumen production in 2006 and upgrading operations in 2007. In Yemen, production from the BAK-A field on Block 51 came on stream in November, just 11 months after sanctioning and we had encouraging results from our exploration program on the block. Offshore West Africa, drilling on OPL-222, offshore Nigeria, resulted in a significant extension of the Usan discovery. We also began exploration of OML-115, offshore Nigeria, and Block K, offshore Equatorial Guinea.

In the fourth quarter, we acquired EnCana Corporation's UK North Sea assets for US$2.1 billion in cash, subject to certain adjustments. The assets include the Buzzard development, Scott and Telford producing fields, several undeveloped discoveries, over 700,000 net exploratory acres and the team that built these assets.

Our US$2.1 billion North Sea acquisition establishes a new core area for us.

This acquisition creates a new core area for us. The Buzzard development is currently on schedule to deliver oil volumes in late-2006. Scott and Telford are currently producing approximately 19,000 boe/d before royalties and there are opportunities in these fields and surrounding acreage to increase production over the next few years.

In 2004, we saw production increases from our deep-water Gulf of Mexico properties, Syncrude, and late-year contributions from Block 51, Scott and Telford—all higher margin assets. However, these increases were not able to overcome the declines from our maturing asset base at Masila in Yemen, in Canada, and in the shallow-water Gulf of Mexico. We reached final production from our Buffalo field in Australia in the fourth quarter. In addition, our 2003 production volumes included 6,200 boe/d before royalties of production relating to Canadian assets sold in August 2003.

We added 123 mmboe of proved reserves after royalties, mostly in the North Sea and at Syncrude. No proved reserves were booked at Long Lake.

We added 123 mmboe of proved oil and gas reserves after royalties, including 13 million barrels relating to our Syncrude operations. Most of these additions related to the North Sea acquisition and Syncrude expansion, offset by some negative revisions in Yemen and Canada. At our Long Lake oil sands project, SEC regulations require us to represent bitumen reserves for this project rather than upgraded synthetic crude oil reserves we plan to sell from the lease. As a result, we recognized 241 million barrels of proved bitumen reserves on sanctioning. At year-end, low bitumen prices and high diluent and natural gas prices resulted in the write-off of our proved bitumen reserves. However, our Long Lake Project is designed to produce and upgrade bitumen into high-quality synthetic crude oil in a fully integrated process which requires no diluent or purchased natural gas. As a result, the economic returns from this process are not dependent on bitumen, diluent and natural gas prices. This write-off has no impact on our decision to proceed with this project.

We financed our North Sea acquisition with cash on hand and bridge financing facilities, increasing our net debt by about $2.6 billion. Historically, we have used leverage to finance major expansions of our business, such as the Yemen Masila project in 1993, the Wascana acquisition in 1997, and the Aspen acquisition in 2002. In all cases, we have successfully used cash flow from these assets to subsequently reduce our net debt. In 2005, we plan to reduce net debt with approximately $1.5 billion in asset dispositions.

Our planned 2005 capital program of $2.6 billion is focussed on progressing our major development projects and drilling over 20 high-potential exploration wells in the Gulf of Mexico, offshore West Africa, North Sea and in Yemen. Less than 20% will be re-invested in our core assets to sustain production and cash flow.

By late-2006, we'll have almost $5 billion invested in multi-year projects not yet producing oil or cash flow.

Going forward, we are well positioned for growth. At the end of 2004, we had over $3 billion of capital invested in multi-year development projects not yet producing oil or cash flow. This amount is expected to peak in late-2006 at approximately $5 billion, as we bring Buzzard and Long Lake on-stream. We expect net debt to decrease significantly once these projects start contributing cash flow in late-2006 and in 2007, respectively.

Our share of incremental production and cash flow from this investment is expected to be significant. Block 51 in Yemen is expected to reach close to 25,000 bbls/d before royalties, in mid-2005. Syncrude's Stage 3 expansion is expected to come on stream in early-2006 adding an incremental 8,000 bbls/d before royalties. Buzzard is on schedule for production start-up planned for late-2006 with production ramping up to 80,000 boe/d before royalties in 2007. At Long Lake, bitumen production is planned to begin in late-2006. In the second half of 2007, this bitumen will be upgraded to 30,000 bbls/d of premium synthetic crude oil when the upgrader comes on stream. Later in the decade, we expect to see significant new production volumes from OPL-222, offshore Nigeria.

In 2007, we expect to produce between 300,000 and 350,000 boe/d before royalties.

Overall, we expect our oil and gas production before royalties to grow to between 300,000 and 350,000 boe/d in 2007, after projected asset sales and base declines. We have assumed exploration success contributes little volume to these estimates.

Most of our new production is subject to little or no royalty payments and generates significantly higher cash margins than our current production. As a result, we expect our production after royalties to grow to between 260,000 and 300,000 boe/d in 2007.

CAPITAL INVESTMENT

(Cdn$ millions)	Estimated 2005	2004	2003
New Growth Development	1,675	682	358
New Growth Exploration	435	266	329
Core Asset Development	435	634	589
	2,545	1,582	1,276
Acquisitions	-	2,587	164
Total Oil & Gas and Syncrude	2,545	4,169	1,440
Chemicals, Marketing and Other	50	95	54
Total Capital	**2,595**	**4,264**	**1,494**

Our strategy and capital programs are focused on growing long-term value for shareholders. To maximize value, we invest in:

- core assets for short-term production and free cash flow to fund ongoing capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow; and
- exploration projects for longer-term growth.

As conventional basins in North America mature, we are transitioning our operations towards less mature basins and unconventional resources in more mature basins. These include the North Sea, Athabasca oil sands, Gulf of Mexico, offshore West Africa and the Middle East—basins which we believe have attractive fiscal terms and significant remaining opportunity.

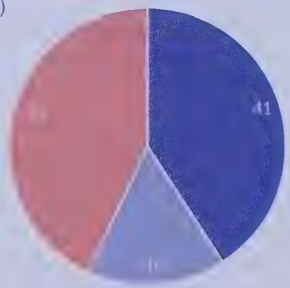
Our capital program supports short, mid and long-term growth.

2004 Investment Program

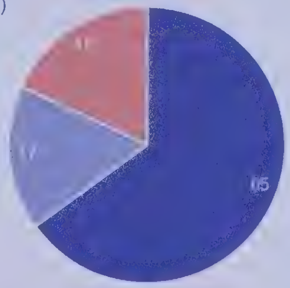
In 2004, we invested almost $4.3 billion, comprising $1.7 billion in capital expenditures and $2.6 billion related to our North Sea acquisition. Excluding this acquisition, most of our capital was invested in multi-year development projects and long cycle-time exploration. Here is the breakdown of our capital investment:

(Cdn$ millions)	New Growth Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas				
Synthetic (mainly Long Lake)	343	19	-	362
North Sea	46	4	7	57
Yemen	112	19	155	286
United States	-	133	267	400
Canada	17	27	131	175
Other Countries	-	64	24	88
Syncrude	164	-	50	214
	682	**266**	**634**	**1,582**
Chemicals	-	-	58	58
Marketing, Corporate and Other	-	-	37	37
Total Capital	**682**	**266**	**729**	**1,677**
As a % of Total Capital	41%	16%	43%	100%

2004 Capital
(%)



2005 Estimated Capital
(%)



■ New Growth Development ■ New Growth Exploration ■ Core Asset Development

We are shifting our capital: investing less in maturing core assets and more in attractive multi-year projects.

2005 Estimated Capital

We'll invest over 80% of 2005 capital on major projects and exploration.

In 2005, we are managing our largest development and exploration program ever. We plan to invest over $2.5 billion on our oil and gas and Syncrude assets before considering the impact of dispositions. Around 65% of this is focused on multi-year development projects, with the remainder split equally between new growth exploration and our core assets.

(Cdn$ millions)	New Growth Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas				
Synthetic (mainly Long Lake)	765	-	-	765
North Sea	590	50	45	685
Yemen	200	-	70	270
United States	-	215	100	315
Canada	-	60	140	200
Other Countries	-	110	25	135
Syncrude	120	-	55	175
	1,675	435	435	2,545
Chemicals	-	-	17	17
Marketing, Corporate and Other	-	-	33	33
Total Capital	1,675	435	485	2,595
As a % of Total Capital	65%	17%	18%	100%

NEW GROWTH DEVELOPMENT

Long Lake Project

Our Long Lake and Buzzard developments are on schedule and on budget.

Almost half our new growth development capital is being invested at Long Lake. The project remains on schedule and on budget. Drilling of the commercial SAGD wells began in late-2004 and will continue throughout 2005. Construction of the SAGD and upgrader facilities is expected to begin in 2005, with the SAGD facilities to be completed in late-2006 and the upgrader in 2007. The upgrader is expected to come on stream in the second half of 2007 with our share of bitumen production ramping up to 36,000 bbls/d (approximately 30,000 bbls/d of synthetic crude oil production).

We are continuing to operate the three well-pair SAGD pilot to optimize performance and gain a better understanding of our operating requirements. To date, we have experienced higher than expected steam-to-oil ratios primarily as a result of the existence of lean zones which absorb the steam without increasing the oil flow. Late in 2004, we shut in one well-pair and reduced the operating pressure of the remaining two well-pairs to see if we could reduce fluid losses into the lean zones. As a result, we have seen fluid losses decline, and our steam-to-oil ratio is continuing to drop. Production is now averaging 500 to 600 bbls/d per well-pair, in line with industry experience and our expectations given the reduced operating pressures.

As a result of our core hole and horizontal drilling for the commercial SAGD wells, we are confident that the lean zone density in the commercial area is lower than the pilot area. We expect to operate most of our commercial wells at higher pressures than the current operating pressures of the SAGD pilot. Higher operating pressures increase well productivity.

To ensure certainty and reliability of bitumen production when we begin upgrading, we are accelerating one well pad consisting of 13 well pairs. This pad will be drilled and tied-in after the current 65 well pairs, for a gross cost of $98 million. While there is no change to total project costs, accelerating this drilling capital increases the total gross capital to upgrader start-up from $3.4 billion to $3.5 billion. We expect to have sufficient bitumen supply to fill our upgrader to capacity as a result of the accelerated drilling of the well pairs and the lower lean zone density.

North Sea should be producing about 120,000 boe/d after royalties in 2008.

To the end of December, approximately 35% of the project's total costs are committed and 20% of these costs have been incurred. Costs to date are consistent with our original estimates and the project is on time and on budget.

North Sea Development

Following our acquisition in the North Sea, we invested $46 million in Buzzard. In 2005, we plan to invest approximately $530 million for development drilling, pipeline installation and facility construction. This development is on budget and on schedule to begin production in late-2006, with our share of production expected to ramp up to 80,000 boe/d before royalties during 2007.

We also plan to evaluate and start developing a number of smaller discoveries on our North Sea acreage. These discoveries contribute to the expected doubling of non-Buzzard production in the North Sea by 2008. The first of these projects, Farragon, is scheduled to come on stream in late-2005, with our share of production reaching between 3,000 and 4,000 boe/d before royalties by early-2006.

Yemen Block 51

At Block 51, we began first oil production ahead of schedule in mid-November. Production from the BAK-A field was producing 16,700 bbls/d before royalties at year-end. Early production from several development wells is handled through temporary production facilities and a new 22-km oil pipeline that connects to the existing Masila export pipeline. We expect to reach full production of 25,000 bbls/d before royalties late in the second quarter of 2005. Another 15 development wells are planned throughout 2005.

We are developing our second Block 51 discovery, BAK-B. The field will initially be developed with five wells and is expected to come on stream in late-2005. We expect the BAK-A and BAK-B fields to maintain production at approximately 25,000 bbls/d before royalties, through 2007. We also expect to have sufficient capacity with our production facilities to handle any additional growth that may come from exploration success on the block.

Syncrude Stage 3 Expansion

We expect the Syncrude expansion to be completed in early-2006, adding 8,000 bbls/d before royalties of synthetic crude net to our 7.23% interest in the joint venture. In 2005, we will focus on completing and commissioning the upgrader expansion and increasing bitumen production supply.

NEW GROWTH EXPLORATION

We remain committed to exploration for longer-term growth. Like other aspects of our business, our exploration portfolio has undergone a transition. Once characterized by non-operated, high-risk prospects, our program is focussing more on prospects that are operated, so we control timing, and have lower-risk. We have a balance of short and longer cycle-time prospects. Many are also located near existing infrastructure, allowing for relatively quick tie-in upon success.

We remain committed to exploration for longer-term growth and have both short and longer cycle-time prospects.

We had a very active exploration program in 2004. We had success on OPL-222 in Nigeria, and in the Gulf of Mexico at Tobago, Dawson Deep and most recently Wrigley and Anduin. We will book proved reserves for these discoveries once commercial projects are sanctioned.

Below are the results of our 2004 exploration program:

Well	Location	Interest	Well Results
Nigeria:			
Usan-5	OPL-222	20% non-operated	sampled oil in several intervals
Usan-6	OPL-222	20% non-operated	flowed at restricted rate of 5,800 bbls/d from one interval
Ameena	OML-115	40% operated	well abandoned
Equatorial Guinea:			
Zorro	Block K	50% operated	well abandoned
Yemen:			
BAK-C	Block 51	87.5% operated	well abandoned
BAK-E	Block 51	87.5% operated	well abandoned
BAK-I	Block 51	87.5% operated	encountered oil shows; testing in progess
US Gulf of Mexico:			
Shark	South Timbalier 174	40% non-operated	well abandoned
Dawson Deep	Garden Banks 625	15% non-operated	discovery expected to begin producing in late-2005 through sub-sea tie-back to the Gunnison SPAR
Tobago	Alaminos Canyon 858/859	13.34% non-operated	discovery temporarily abandoned; possibly part of future regional development
Crested Butte	Green Canyon 242	100% operated	well abandoned as oil shows were close to salt; further work required to see if side-track warranted
Main Pass 240	Main Pass 240	45% non-operated	well abandoned
Fawkes	Garden Banks 303	33 ⅓% non-operated	well abandoned
Wind River	West Cameron 335	50% non-operated	well abandoned
Wrigley	Mississippi Canyon 506	50% non-operated	gas discovery expected on stream mid-2006
Anduin	Mississippi Canyon 754/755	50% operated	encountered oil shows; side-tracking to delineate

16 wells drilled:
6 successful
1 requires testing
9 abandoned
See page 44 for dry-hole costs expensed.

In 2005, we plan to drill more than 20 high-potential wells.

Our US program was delayed in 2004 due to rig delays and storms, but we plan to drill up to 10 exploration wells in the Gulf in the next year. This includes major deep-water, sub-salt prospects at Vrede, Knotty Head and Pathfinder. Most of the drilling rigs are lined up, partner approvals are in place and we are looking forward to the results of this program.

Overall, we expect to drill more than 20 high-potential wells in 2005, with most of these to be drilled in the first half of the year. Internationally, we are planning to drill exploration wells offshore West Africa, at least four wells in the North Sea and four wells on Block 51 in Yemen.

We already have three wells underway with results expected in the first half of 2005:

Region	Well	Location	Interest
US Gulf of Mexico	Big Bend	Mustang Island A-110	50% non-operated
US Gulf of Mexico	Vrede	Atwater Valley 223/224/267/268	25% non-operated
Yemen	BAK-J	Block 51	87.5% operated

In Canada, we continue to focus on large unconventional resource opportunities. We expect to establish commerciality of our Upper Mannville CBM pilot at Corbett in 2005, setting the stage for full field development, and to continue evaluating other Upper Mannville and Horseshoe Canyon CBM prospects. We also plan to continue a number of enhanced oil recovery pilot projects on our heavy oil properties in west central Saskatchewan. These projects are evaluating technologies to increase recovery of our extensive heavy oil properties.

CORE ASSETS

Core asset investment is focussed on maximizing returns, not just increasing production or reserves.

We are limiting our capital investment in core assets: the Gulf of Mexico shelf, Masila in Yemen, and Western Canada. Generally, only 20% of the cash flow they generate is being reinvested back into these assets. Our goal is to maximize value from these assets in the form of returns, not necessarily increasing reserves or production. By maximizing value, we also generate significant free cash flow from these assets to help fund our major development projects and new growth exploration.

In the Gulf of Mexico, we tied-in the third development well at Aspen and the remaining development wells at Gunnison. In 2005, our development program will focus on a number of shallow-water gas opportunities in the Eugene Island and Vermilion areas. In the deep-water, we intend to drill and tie back two sub-sea wells and the Dawson Deep discovery to the Gunnison SPAR.

In the North Sea, we plan to drill, complete and tie-in five development wells in the Scott/Telford area, work-over several existing wells and de-bottleneck and upgrade production facilities on the Scott platform in 2005.

In Yemen, the Masila Block continues to generate value. At the end of 2004, we have produced approximately 80% of Masila's expected reserves and have generated more than US$1.5 billion of free cash flow, net to us. As we continue to deplete the remaining reserves, we expect to recover more than $1.4 billion of additional free cash flow before the primary term of our production sharing agreement expires in 2011.

The Masila fields are maturing and we are managing the pace of our drilling program to between 20 and 40 wells per year to ensure we recover the remaining reserves in the most economic and prudent manner. In 2005, we plan to drill at least 20 wells to further develop existing fields and test deeper horizons where we have had recent success. We expect our share of Masila production to be between 74,000 and 84,000 bbls/d before royalties and to generate approximately $300 million of free cash flow.

In Canada, we continue focusing on maximizing value from our existing assets through infill drilling, optimizing production from existing wells and reducing operating costs.

CHEMICALS

In the fourth quarter, our Brandon chemicals operations completed their sixth expansion using relocated equipment from our idled Louisiana facility. The expansion increased sodium chlorate production by 65,000 tonnes per year, raising the annual plant capacity to over 260,000 tonnes. The Brandon plant is now the largest sodium chlorate plant in the world, and we are one of the largest and lowest cost producers of sodium chlorate in North America. Low input and operating costs here are expected to help lower our overall manufacturing cost of sodium chlorate. Activities in 2005 will focus on maintaining existing infrastructure and limiting plant downtimes.

The expansion at Brandon makes it the world's largest sodium chlorate plant.

MARKETING, CORPORATE AND OTHER

In 2004, we continued implementing and realizing full benefits from our SAP and other information technology platforms.

FINANCIAL RESULTS

Year to Year Change in Net Income

(Cdn$ millions)	2004 vs 2003	2003 vs 2002	
Net Income for 2003 and 2002[1]	**578**	**409**	
Favourable (unfavourable) variances:			
Cash Items:			
Production volumes, after royalties:			
Crude oil	(116)	51	
Natural gas	(8)	41	
Change in crude oil inventory	40	(25)	**For more info, see:**
Total volume variance	(84)	67	page 36
Realized commodity prices:			
Crude oil	365	48	
Natural gas	-	234	
Total price variance	365	282	page 39
Oil and gas operating expense:			
Conventional	(55)	46	
Synthetic	(2)	(14)	
Total operating expense variance	(57)	32	page 42
Marketing contribution	(14)	96	page 46
Chemicals contribution	10	(5)	page 48
General and administrative	(39)	(34)	page 49
Interest expense	26	12	page 50
Current income taxes	(38)	13	page 50
Other	(22)	21	page 51
Total Cash Variance	**147**	**484**	
Non-Cash Items:			
Depreciation, depletion, amortization and impairment:			
Oil & Gas and Syncrude	271	(312)	page 43
Other	13	(5)	
Exploration expense	(45)	(12)	page 44
General and administrative	(70)	(4)	page 49
Future income taxes	(176)	34	page 50
Other	75	(16)	page 51
Total Non-Cash Variance	**68**	**(315)**	
Net Income for 2004 and 2003	**793**	**578**	

Note:
1 Includes results of discontinued operations (see Note 11 to our Consolidated Financial Statements).

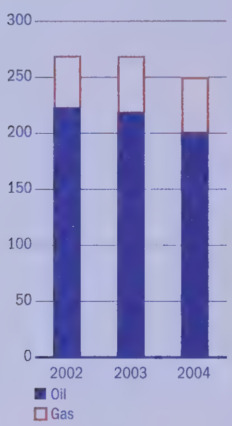
Significant variances in net income are explained in the sections that follow. The impact of foreign exchange on our operations is summarized on page 51.

OIL & GAS AND SYNCRUDE

Production

All volumes discussed below are our working interest volumes.

Production before Royalties
(mboe/d)



	2004		2003		2002	
	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties	Before Royalties[1]	After Royalties
Oil and Liquids (mbbls/d)						
Yemen	107.3	53.5	116.8	57.5	118.0	55.8
Canada[2]	36.2	28.2	46.3	35.4	56.3	43.4
United States	30.0	26.5	28.3	25.0	9.9	8.2
Australia[3]	2.7	2.5	6.1	5.6	12.8	10.3
United Kingdom	1.5	1.5	-	-	-	-
Other Countries	5.3	4.7	5.4	4.6	8.9	5.2
Syncrude (mbbls/d)[4]	17.2	16.6	15.3	15.2	16.6	16.5
	200.2	133.5	218.2	143.3	222.5	139.4
Natural Gas (mmcf/d)						
Canada[2]	146	115	158	125	167	128
United States	148	126	145	122	112	93
United Kingdom	3	3	-	-	-	-
	297	244	303	247	279	221
Total (mboe/d)	**250**	**174**	**269**	**185**	**269**	**176**

Notes:

1 We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

2 Includes the following production from discontinued operations. See Note 11 to our Consolidated Financial Statements.

(mboe/d)	2004	2003	2002
Production			
Before Royalties	-	6.2	10.5
After Royalties	-	4.6	7.8

3 Comprises production from discontinued operations. See Note 11 to our Consolidated Financial Statements.

4 Considered a mining operation for US reporting purposes.

2004 vs 2003—Lower production decreased net income by $84 million

Production after royalties decreased 6% from 2003. Our 2003 production included volumes from our non-core Canadian light oil properties in southeast Saskatchewan that were sold in August 2003. Excluding these volumes, our production after royalties decreased 3%. This table summarizes the change:

Production dropped 6% after royalties and 7% before royalties as new volumes did not offset declines in maturing fields.

(mboe/d)	Before Royalties	After Royalties
2003 Production	**269**	**185**
Sale of non-core Canadian properties	(6)	(5)
	263	180
Production changes:		
Masila Block in Yemen	(11)	(5)
Block 51 in Yemen	1	1
Canada	(6)	(4)
Gulf of Mexico—deep-water	8	7
Gulf of Mexico—shallow-water	(6)	(5)
Australia	(3)	(3)
North Sea	2	2
Syncrude	2	1
2004 Production	**250**	**174**

Production before royalties decreased 7% as new volumes from the deep-water Gulf of Mexico, the North Sea and Block 51 did not offset declines in our maturing conventional assets and late-life assets offshore Nigeria and Australia and the sale of Canadian properties in 2003. Our known future production increases are expected to come from Block 51 in Yemen in 2005, Syncrude in early-2006, first production from Buzzard in the North Sea in late-2006, and from bitumen production in 2006 and synthetic crude in 2007 from the Long Lake Project.

Yemen

Production decreased 8% compared to 2003. The shortfall resulted from declining base production, lower drilling success rates and delays in approvals for our development drilling program. As a result, we drilled 73 development wells rather than the 90 planned, and this drilling was unable to keep up with base declines. In 2005, we plan to drill at least 20 wells.

First oil from Block 51 was achieved ahead of schedule.

First production from Block 51 commenced in November 2004 with initial rates around 4,000 bbls/d. By mid-2005, we expect production to ramp up to approximately 25,000 bbls/d before royalties as permanent production facilities, including water handling facilities, are commissioned.

We expect production from Masila and Block 51 to average between 90,000 and 100,000 bbls/d before royalties in 2005.

Canada

Production was down 9% from 2003, after adjusting for the August 2003 sale of non-core, light-oil properties in southeast Saskatchewan. To maximize value, we continue to manage our maturing conventional assets in Western Canada through selective development, cost control and asset dispositions. In 2005, we expect them to produce between 52,000 and 56,000 boe/d before royalties, net to us. Looking ahead, we expect increases as the Long Lake Project starts up with bitumen production in 2006 and synthetic crude in 2007. We are considering the sale of certain Canadian oil and gas properties in 2005. Any sale of assets would reduce our 2005 production volumes.

Gulf Of Mexico

Production averaged an all-time high of 54,700 boe/d before royalties, 4% higher than last year, due to new deep-water volumes at Aspen and Gunnison.

Our deep-water production grew 8,000 boe/d before royalties over 2003 levels. These high-margin volumes contribute cash netbacks almost twice our corporate average. The third Aspen development well, brought on stream in July, is currently producing 16,200 boe/d before royalties. However, we experienced higher water cuts on our Aspen-1 well and completed an intervention, attempting to reduce these cuts. The well was shut-in for most of August to complete this work. To date, the response has not met our expectations as there has been no increase in oil production or decrease in water production. We are currently producing 24,500 boe/d before royalties from all three wells.

We added 8,000 boe/d before royalties of high-margin barrels in the deep water. These fuelled our corporate netbacks. See page 45.

We completed the tie-in of the remaining wells at Gunnison which added 9,000 boe/d before royalties in 2004. These volumes were less than expected as one well sanded up in early May and another encountered tar on completion. We successfully re-completed the well that sanded up and brought it back on stream in mid-August. A sidetrack on the tar well was completed and this well started producing from one of three intervals in mid-December. We expect to produce from all three intervals by the end of February 2005.

Our shallow-water production declined 6,000 boe/d before royalties compared to 2003, caused by base declines and delays in our development program. We had planned an expanded development program in the second half of the year, but it was delayed due to rig delivery, storms and drilling problems. Development drilling at Vermilion 302/320, West Cameron 170 and Vermilion 76 helped mitigate declines.

We expect production from the Gulf of Mexico to average between 50,000 and 60,000 boe/d in 2005.

North Sea

The acquired Scott and Telford fields contributed production for December 2004, adding 2,000 boe/d before royalties to our annual average. In 2005, we expect these fields to produce between 14,000 and 18,000 boe/d before royalties, net to us.

Other Countries

Australia is fully depleted and Nigeria is to be depleted in 2005.

Australia produced its final barrel in November and abandonment activities are proceeding. We expect abandonment activities to be completed in 2005. Production from Colombia grew 50% from 2003 to 4,800 bbls/d before royalties as we continue to implement our development program at Guando. We continue to produce small volumes from the Ejulebe field offshore Nigeria, but we expect final production in the first half of 2005.

Syncrude

Syncrude produced a record 17.2 mboe/d before royalties, net to us.

Syncrude achieved a new annual production record despite operating problems towards the end of the year. In November, we experienced an unscheduled coker shut-down. After the coker had returned to full capacity in early December, a major electrical interruption led to the shut-down of the LC finer for the rest of the year. The LC finer has returned to full capacity. Turnarounds on the coker and hydrotreater units in early-2005 are expected to cause first quarter production to be lower than planned by 25%. We expect 2005 Syncrude volumes of between 16,000 and 18,000 bbls/d before royalties, net to us.

2003 vs 2002—5% production growth after royalties added $67 million to net income

Production after royalties grew 5%, with new low-royalty, deep-water production from Aspen and Gunnison, and more cost recovery barrels from Masila in Yemen. At Masila, we received a greater percentage of gross production to recover costs incurred.

Production before royalties was flat compared to 2002 as growth in our US deep-water production was partially offset by dispositions in Canada, production declines offshore Nigeria and Australia, and maturing conventional assets. Production from the Masila block in Yemen decreased slightly in 2003 consistent with the overall decline in the field's base production. In Canada, we aggressively managed our assets by developing them where we could add value or by selling them at attractive prices where this maximized value. A full year of deep-water Aspen production increased US production rates 84% to record levels in 2003. Production adds and optimization activities at Eugene Island 295 and Vermilion 76 offset declines on the Shelf.

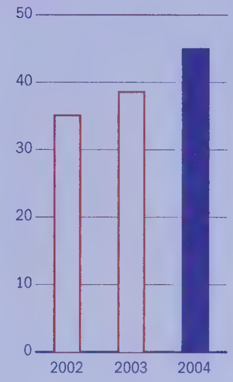
Our production at Buffalo, offshore Australia and at Ejulebe, offshore Nigeria declined as expected throughout 2003 as both fields approached the end of their economic life. Syncrude production decreased 8% in 2003 as an unplanned additional coker turnaround was completed during the year.

Commodity Prices

	2004	2003	2002
Crude Oil			
West Texas Intermediate (US$/bbl)	41.40	31.04	26.09
Differentials[1] (US$/bbl)			
Masila	4.84	3.03	1.41
Heavy Oil	13.53	8.63	6.49
MARS	6.15	3.53	2.51
Producing Assets (Cdn$/bbl)			
Yemen	47.59	39.45	38.80
Canada	36.60	32.37	31.13
United States	46.60	37.68	38.88
Syncrude	52.80	43.36	40.89
Australia	51.22	43.14	40.30
North Sea	46.81	-	-
Other Countries	43.07	38.22	38.96
Corporate Average (Cdn$/bbl)	45.90	38.04	37.13
Natural Gas			
New York Mercantile Exchange (US$/mmbtu)	6.19	5.60	3.37
AECO (Cdn$/mcf)	6.44	6.35	3.84
Producing Assets (Cdn$/mcf)			
Canada	5.76	5.64	3.57
United States	7.89	8.16	5.29
North Sea	8.28	-	-
Corporate Average (Cdn$/mcf)	6.85	6.85	4.25
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	44.94	38.63	35.14
Average Foreign Exchange Rate—Canadian to US Dollar	0.7683	0.7135	0.6369

Note:
1 These differentials are a discount to WTI.

Averaged Realized Oil and Gas Price
(Cdn$/boe)



2004 vs 2003—Higher realized prices added $365 million to net income

Crude oil prices reached record levels in 2004, supported by supply concerns, high demand and speculative traders increasing volatility to all-time highs. The positive impact of strong crude oil reference prices was offset in part by the weakening US dollar and widening crude oil quality differentials.

All of our oil sales and most of our gas sales are denominated in or referenced to US dollars. As a result, a stronger Canadian dollar relative to the US dollar reduced our realized crude oil price by $3.50/bbl and our realized natural gas price by $0.50/mcf. In total, our net sales decreased $220 million from 2003 due to the weakening US dollar. The Canadian to US dollar exchange rate closed the year at 83¢.

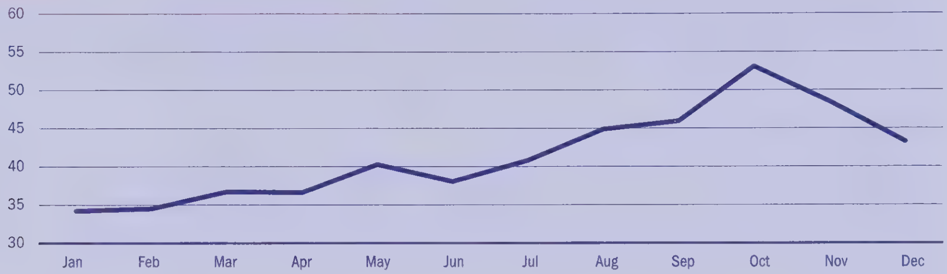
A stronger Canadian dollar reduced our realized oil and gas prices and dropped net sales by $220 million.

WTI oil price was 33% higher than in 2003, reflecting supply concerns.

Crude Oil Reference Prices

Crude oil prices reached record highs in 2004 and West Texas Intermediate (WTI) averaged US$41.40/bbl in 2004, 33% higher than its 2003 average of US$31.04/bbl. At its peak, WTI broke through US$55/bbl. Strong demand and concerns around supply disruptions and inventories, coupled with significant volatility, contributed to the increase.

2004 Oil Prices (WTI Monthly Average)
(US$/bbl)



Strong global demand, led by China and India, prevailed throughout much of 2004. Even as WTI reached successive record highs late in the year, demand for crude oil, particularly sweet blends, remained strong globally. While global demand drove crude oil prices up, actual and potential supply concerns supported major price moves:

- terrorist activities in Iraq continued throughout the year, disrupting supply on several occasions;
- attacks in Saudi Arabia called into question not only the security of current supply, but also the security of the only significant spare capacity globally;
- on-going civil unrest in Nigeria and Venezuela impacted their ability to export crude;
- labour disputes and safety concerns in the North Sea disrupted supply on several occasions, increasing concerns around already tight European supply;
- Hurricane Ivan disrupted supply from the Gulf of Mexico in the third quarter and increased concern over low inventory levels in the US; and
- the Yukos bankruptcy crisis reduced expected production increases from Russia.

OPEC responded by increasing output on several occasions, but these increases were not enough to change the perception that there was insufficient stable supply to meet demand.

We expect strong crude oil prices in 2005.

These events caused significant oil price volatility. As a result, traders and longer-term commodity investors, flocked to the market, pushing daily trading bands higher than previously observed. Traders' positions and related profit-taking created more volatility. With supply concerns, growing speculation and continued volatility, we expect to see high crude oil prices continue into 2005.

Widening differentials reduced the price we received for our heavy oil, Masila and Aspen volumes.

Crude Oil Differentials

Crude oil differentials were wide in 2004 due mostly to strong benchmark prices. Growing global demand for diesel and gasoline has created a premium for light, sweet crudes. Incremental heavy, sour barrels brought on by OPEC throughout the year widened out the light/heavy differentials even further. The Canadian heavy oil differential widened to average US$13.53/bbl, as light, sweet blends increased in value relative to heavy, sour blends. Although differentials were wide, the normal seasonal patterns held true which narrows the heavy oil differential through the summer when there is increased demand due to road construction. Heavy oil differentials reached a record-wide US$22.67/bbl in December from these factors.

The WTI/Brent differential (relevant for our Masila crude and North Sea production) widened to average US$3.19/bbl in 2004 compared to US$2.20 in 2003. Higher freight rates due to increased production out of the Middle East made Brent more expensive to purchase, thereby decreasing its value relative to WTI.

The Masila differential tracked the Brent/WTI spread very closely through the first eight months of the year, but widened relative to both WTI and Brent late in the year. As with Canadian heavy oil differentials, our Masila barrels were impacted by the increased supply of heavy, sour oil from the Middle East later in the year and strong demand by Asian refiners for lighter blends. The differential reached US$7.84/bbl in the fourth quarter, compared to its annual average of US$4.84.

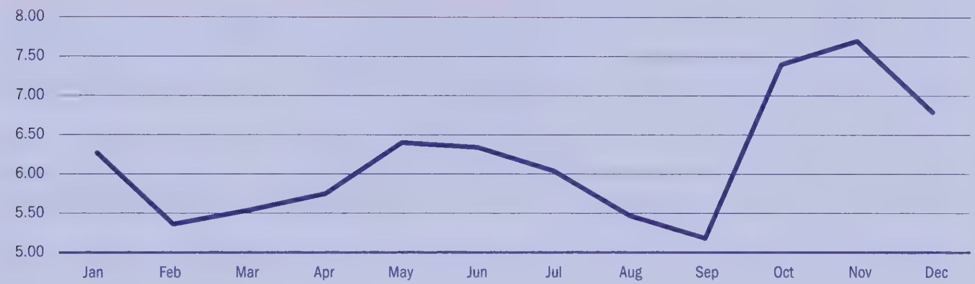
Similar to Canadian heavy oil and Masila, the MARS differential (relevant for Aspen) widened on the strength of WTI and the increased supply of world heavies.

Natural Gas Reference Prices

Natural gas prices remained strong in 2004, buoyed by high crude oil prices and tight long-term supply and demand fundamentals. In 2004, NYMEX averaged US$6.19/mcf, 11% higher than 2003. Weather was reasonably mild in North America, causing a strong build in inventory levels into winter.

NYMEX gas price was 11% higher than in 2003, reflecting concerns that supply could not keep pace with demand.

2004 Natural Gas Prices (NYMEX Monthly Average)
(US$/mmbtu)



At year-end, inventory levels were 3% higher than 2003 and 11% higher than the five-year average. Despite this, long-term concerns remain around the ability of supply to keep up with demand from North American utilities. As a result, we expect prices to remain above US$5/mmbtu into the future. Even with short-term bearish fundamentals, prices tracked their normal seasonal pattern and remained relatively strong into winter, consistent with higher heating oil prices.

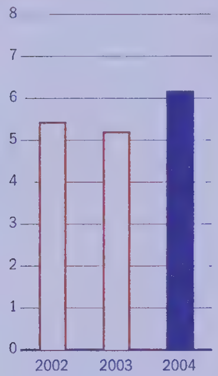
We expect prices to remain above US$5/mcf into the future.

2003 vs 2002—Higher realized prices added $282 million to net income

Both crude oil and natural gas commodity prices reached near record levels in 2003 as supply and demand fundamentals supported strong prices. The positive impact of strong crude oil and natural gas reference prices was offset in part by the stronger Canadian dollar and wider crude oil differentials.

Since all of our oil sales and most of our gas sales are denominated in or referenced to US dollars, the strengthening Canadian dollar relative to the US dollar reduced our realized crude oil price by $4.50/bbl and our realized natural gas price by $0.80/mcf. In total, our net sales decreased $280 million from 2002 levels because of the stronger Canadian dollar. The Canadian to US dollar exchange rate closed the year at 77¢.

Operating Costs Before Royalties
(Cdn$/boe)



Higher operating costs per boe reflect lower volumes and increased maintenance and workovers.

Operating Costs

(Cdn$/boe)	2004 Before Royalties[1]	2004 After Royalties	2003 Before Royalties[1]	2003 After Royalties	2002 Before Royalties[1]	2002 After Royalties
Conventional Oil and Gas						
Yemen	2.80	5.64	2.16	4.37	1.95	4.13
Canada	7.12	8.98	6.00	7.76	5.70	7.45
United States	5.30	6.12	4.49	5.19	9.09	10.87
Australia	32.94	35.73	18.60	20.21	9.76	12.14
United Kingdom	8.26	8.26	-	-	-	-
Other Countries	3.76	4.09	7.47	9.01	6.21	10.69
Average Conventional	5.13	7.59	4.17	6.24	4.60	7.24
Synthetic Crude Oil						
Syncrude	19.89	20.61	21.96	22.18	18.10	18.21
Average Oil and Gas	6.15	8.83	5.19	7.56	5.42	8.26

Note:
1 Operating costs per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2004 vs 2003—Higher oil and gas operating costs decreased net income by $57 million

Our operating costs have increased as a result of high-cost, late-life barrels in Australia, higher maintenance costs in Yemen and Canada, more workover and remediation activity in the Gulf of Mexico and the spread of fixed costs over fewer barrels.

Flow line replacements, higher water handling costs and increased maintenance at Masila in Yemen increased our corporate unit operating costs by 30¢/boe. However, these increased Yemen costs only reduce our corporate netbacks by 5¢/boe as a result of the cost recovery mechanism contained in our production sharing agreement.

Operating costs in Canada were slightly lower than 2003, but because of declining volumes, our corporate average unit costs increased by 25¢/boe. We expect our unit costs to continue to increase with increased water handling, higher labour costs and declining volumes.

Aspen-1 intervention costs of $12 million were expensed during the year. They were higher than expected as storm activity in the Gulf extended the work. These costs, together with higher workover activities on the Shelf, contributed a 28¢/boe increase to our corporate unit costs.

Australia produced its final barrel in November. These expensive late-life barrels increased our corporate unit costs by 30¢/boe but high crude prices allowed us to produce them economically.

The incremental North Sea barrels added 7¢/boe to our corporate average for the year.

The strength of the Canadian dollar reduced our US-dollar denominated operating costs, contributing a 25¢/boe reduction to our corporate unit costs.

Syncrude's operating costs were flat compared to 2003, but because of increased volumes, unit costs decreased 9%. Higher natural gas input costs were offset by lower maintenance costs in 2004 since there was not a major coker turnaround. As more expensive Syncrude barrels were a larger portion of our total corporate production in the year, our corporate unit operating costs increased by 17¢/boe.

2003 vs 2002—Lower oil and gas operating costs increased net income by $32 million

Conventional unit operating costs decreased as we added low-cost Aspen production in the Gulf of Mexico and the Canadian dollar strengthened relative to the US dollar. Increased workover and maintenance activity in Yemen and higher water handling costs in Canada partially offset this decrease.

Low-cost Aspen production reduced US operating costs by 50% and lowered our corporate average unit operating costs by approximately 40¢/boe. Aspen production costs are lower than our corporate average for conventional production as most of the costs in the deep-water are capital related.

The strengthening Canadian dollar decreased US-dollar denominated operating costs, lowering our corporate average unit operating costs by approximately 25¢/boe. Higher repairs, increased maintenance and workover activity resulted in a 55¢/bbl increase in Yemen operating costs. However, these increased Yemen costs only reduced our corporate netbacks by 14¢/boe as a result of the cost recovery mechanism contained in our production sharing agreement. As well, unit operating costs offshore Australia and Nigeria increased as fixed costs were spread over declining production volumes.

Syncrude operating costs increased 21% due to higher natural gas input costs and increased turnaround and maintenance activity in 2003. Lower volumes also increased unit operating costs as more than 95% of the operating costs are fixed.

Depreciation, Depletion, Amortization and Impairment (DD&A)

	2004		2003		2002	
(Cdn$/boe)	Before Royalties[2]	After Royalties	Before Royalties[2]	After Royalties	Before Royalties[2]	After Royalties
Conventional Oil and Gas						
Yemen	4.35	8.77	3.96	8.03	3.47	7.34
Canada[1]	9.02	11.37	9.10	11.76	8.22	10.72
United States	12.93	14.93	10.80	12.47	12.74	15.38
Australia	5.82	6.31	13.31	14.46	10.45	12.99
United Kingdom	22.44	22.44	-	-	-	-
Other Countries	9.90	10.77	17.09	22.47	13.22	22.90
Average Conventional	7.87	11.64	7.37	11.04	6.84	10.81
Synthetic Crude Oil						
Syncrude	2.75	2.85	2.50	2.53	2.13	2.17
Average Oil and Gas	7.52	10.80	7.09	10.33	6.55	10.01

Notes:
1 2003 DD&A per boe excludes the impairment charge described in Note 5 to the Consolidated Financial Statements.
2 DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2004 vs 2003—Lower oil and gas DD&A increased net income by $271 million

Our DD&A expense in 2003 included an impairment charge of $269 million largely attributable to Canadian heavy oil property negative reserve revisions. Excluding this charge from our 2003 per unit DD&A costs, our per unit corporate depletion rate has increased. Higher depletion from our more capital-intensive deep-water properties in the Gulf of Mexico has increased corporate rates by 70¢/boe. These properties, however, benefit from low royalties and lower unit operating costs as most of the costs are capital in nature.

Our DD&A rate is increasing because of more capital-intensive areas including the Gulf of Mexico and North Sea.

Yemen increased our corporate rate by 30¢/boe mainly due to the additional volumes from Block 51, offset slightly by lower volumes at Masila. The North Sea volumes increased our corporate rate by 20¢/boe. Our UK depletion rate of $22.44/boe reflects the depletion of the portion of the acquisition cost allocated to our interests in the Scott/Telford fields on a before-tax basis.

Syncrude depletion rates increased reflecting the depletable costs of the Aurora 2 bitumen train which came into service in late-2003.

By way of offset, we benefited from the strong Canadian dollar as the depletion of our US and International assets is denominated in US dollars. This lowered our depletion rate by 45¢/boe. As well, the depletable costs on our Canadian heavy oil properties were reduced at year-end 2003 and both Australia and Nigeria are nearly fully depleted. The write down of our Canadian heavy oil properties reduced our depletion rate by 31¢/boe and lower volumes in Canada, Australia and Nigeria contributed a combined reduction of 65¢/boe.

2003 vs 2002—Higher oil and gas DD&A reduced net income by $312 million

Conventional depletion rates increased with higher 2002 finding and development costs and our changing production mix, as more capital-intensive properties like Aspen contributed production volumes. These properties, however, deliver higher-margin returns making them a valuable part of our portfolio. We also experienced higher depletion rates offshore Nigeria and Australia, as we prepared to abandon these fields.

The strengthening Canadian dollar offset these increases as our depletion from International and the US is denominated in US dollars. This lowered our corporate average rate by approximately 48¢/boe.

Our 2003 DD&A expense includes an impairment charge of $269 million largely attributable to reserve revisions to Canadian heavy oil properties. These revisions reflected our more conservative view of production profiles for certain properties, proven undeveloped reserves we were no longer certain we could recover and changes in end-of-life economic assumptions.

Exploration Expense[1]

(Cdn$ millions)	2004	2003	2002
Seismic	73	62	80
Unsuccessful Drilling	125	70	61
Other	48	69	48
Total Exploration Expense	**246**	**201**	**189**
New Growth Exploration	266	267	179
Geological and Geophysical Costs	73	62	80
Total Exploration Expenditures	**339**	**329**	**259**
Exploration Expense as a % of Exploration Expenditures	73%	61%	73%

Note:
1 Includes exploration expense from discontinued operations. See Note 11 to our Consolidated Financial Statements.

Increased 2004 exploration expense reflects higher exploration capital. See 2004 drilling results on page 33.

Gulf of Mexico accounts for half our 2004 dry-hole and seismic costs.

2004 vs 2003—Higher exploration expense reduced net income by $45 million

Increased exploration expense reflected the increase in our 2004 exploration capital expenditures. We had further success at Usan on OPL-222, offshore Nigeria, Block 51 in Yemen and at Dawson Deep, Tobago, Wrigley and Anduin in the deep-water Gulf of Mexico. However, unsuccessful drilling included dry holes in the Gulf of Mexico, offshore Nigeria and Equatorial Guinea, and in Yemen.

In the Gulf of Mexico, we had five dry holes: Crested Butte, Main Pass 240, Shark, Fawkes and Wind River. At our 100%-owned Crested Butte well on Green Canyon Block 242, we found oil-bearing sands in many horizons, but the volumes were not commercial so we abandoned the well. Further work is required to determine if a sidetrack is warranted. We expensed $39 million of well costs in the fourth quarter. In 2004, we drilled Main Pass 240 and found the objective sand wet. This well was abandoned in December 2004. Shark was an ultra-deep-shelf gas test on South Timbalier 174 that finished drilling during the first quarter of 2004. Following our evaluation, we expensed $25 million of well costs. While the well has been abandoned, we can re-enter it if required. Fawkes and Wind River, located in deep water, completed drilling and were abandoned in January 2005, resulting in a write-off of $13 million in 2004. Overall, dry hole and seismic costs in the Gulf of Mexico accounted for over 50% of our exploration expense.

Dry hole costs also included the Ameena prospect on OML-115, offshore Nigeria, the Zorro-1 prospect, offshore Equatorial Guinea and two unsuccessful exploration wells on Block 51 in Yemen.

2003 vs 2002—Higher exploration expense reduced net income $12 million

Exploration expense was higher in light of our increased 2003 exploration capital expenditures. We had success in the Gulf of Mexico, OPL-222, offshore Nigeria and Block 51 in Yemen.

Dry hole and seismic costs in the Gulf of Mexico accounted for over 40% of our exploration expense. Exploration in the Gulf yielded some promising results at Shiloh where we found hydrocarbons but not commercial quantities, so the well costs were written off. We were unsuccessful at Santa Rosa.

Dry hole costs also included three wells in the Alberta foothills of Canada, the Andino-1 well in Colombia, the Escargot well offshore Brazil and the HEK well in Yemen on Block 51.

Oil & Gas And Syncrude Netbacks

Netbacks are the cash margins we receive for every equivalent barrel sold. Below are the sales prices, per unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties.

BEFORE ROYALTIES

	2004							
($/boe)	Yemen	Canada	US	Australia	UK	Other	Syncrude	Total
Sales	47.59	35.76	46.94	51.22	47.45	43.07	52.80	44.94
Royalties and other	(23.98)	(7.40)	(6.29)	(4.00)	-	(3.49)	(1.84)	(13.65)
Operating expenses	(2.80)	(7.12)	(5.30)	(32.94)	(8.26)	(3.76)	(19.89)	(6.15)
In-country taxes	(5.82)	-	-	-	-	-	-	(2.48)
Cash netback	**14.99**	**21.24**	**35.35**	**14.28**	**39.19**	**35.82**	**31.07**	**22.66**

	2003							
($/boe)	Yemen	Canada	US	Australia	UK	Other	Syncrude	Total
Sales	39.45	32.99	42.88	43.14	-	38.22	43.36	38.63
Royalties and other	(19.98)	(7.53)	(5.91)	(3.44)	-	(5.69)	(0.48)	(12.14)
Operating expenses	(2.16)	(6.00)	(4.49)	(18.60)	-	(7.47)	(21.96)	(5.19)
In-country taxes	(4.73)	-	-	-	-	-	-	(2.06)
Cash netback	**12.58**	**19.46**	**32.48**	**21.10**	**-**	**25.06**	**20.92**	**19.24**

	2002							
($/boe)	Yemen	Canada	US	Australia	UK	Other	Syncrude	Total
Sales	38.80	27.90	34.21	40.30	-	38.96	40.89	35.14
Royalties and other	(20.45)	(6.53)	(5.82)	(7.88)	-	(16.48)	(0.36)	(12.56)
Operating expenses	(1.95)	(5.70)	(9.09)	(9.76)	-	(6.21)	(18.10)	(5.42)
In-country taxes	(4.81)	-	-	-	-	-	-	(2.10)
Cash netback	**11.59**	**15.67**	**19.30**	**22.66**	**-**	**16.27**	**22.43**	**15.06**

AFTER ROYALTIES

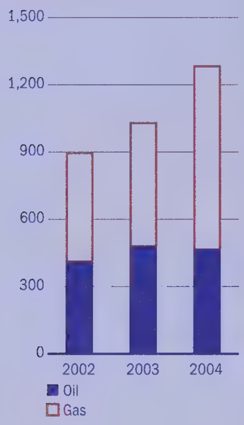
	2004							
($/boe)	Yemen	Canada	US	Australia	UK	Other	Syncrude	Total
Sales	47.59	35.76	46.94	51.22	47.45	43.07	52.80	44.94
Operating expenses	(5.64)	(8.98)	(6.12)	(35.73)	(8.26)	(4.09)	(20.61)	(8.83)
In-country taxes	(11.72)	-	-	-	-	-	-	(3.57)
Cash netback	**30.23**	**26.78**	**40.82**	**15.49**	**39.19**	**38.98**	**32.19**	**32.54**

With little or no royalties, new production from the deep-water Gulf of Mexico and North Sea is driving our corporate netbacks.

	2003							
($/boe)	Yemen	Canada	US	Australia	UK	Other	Syncrude	Total
Sales	39.45	32.99	42.88	43.14	-	38.22	43.36	38.63
Operating expenses	(4.37)	(7.76)	(5.19)	(20.21)	-	(9.01)	(22.18)	(7.56)
In-country taxes	(9.58)	-	-	-	-	-	-	(3.00)
Cash netback	**25.50**	**25.23**	**37.69**	**22.93**	**-**	**29.21**	**21.18**	**28.07**

	2002							
($/boe)	Yemen	Canada	US	Australia	UK	Other	Syncrude	Total
Sales	38.80	27.90	34.21	40.30	-	38.96	40.89	35.14
Operating expenses	(4.13)	(7.45)	(10.87)	(12.14)	-	(10.69)	(18.21)	(8.26)
In-country taxes	(10.17)	-	-	-	-	-	-	(3.20)
Cash netback	**24.50**	**20.45**	**23.34**	**28.16**	**-**	**28.27**	**22.68**	**23.68**

Oil and Gas Volumes Marketed
(mboe/d)



Gas marketing contributed 61% of marketing revenue.

OIL AND GAS MARKETING

(Cdn$ millions)	2004	2003	2002
Revenue	623	568	496
Transportation	(466)	(398)	(423)
Other	(2)	(1)	-
Net Revenue	**155**	**169**	**73**
Marketing Contribution to Income from Continuing Operations before Income Taxes	87	111	35
Natural Gas			
Physical Sales Volumes[1] (bcf/d)	4.9	3.3	2.9
Transportation Capacity (bcf/d)	3.5	2.0	1.2
Storage Capacity (bcf)	27	18	9
Crude Oil			
Physical Sales Volumes[1] (mbbls/d)	465	479	412
Storage Capacity (mbbls)	408	-	-
Value-at-Risk			
Year-end	21	21	19
High	42	31	28
Low	17	14	12
Average	29	20	17

Note:
1 Excludes intra-segment transactions.

2004 vs 2003—Net marketing revenue decreased net income by $14 million

Although more profitable in 2003, marketing had another exceptional year in 2004, with net revenue of $155 million. Gas marketing contributed $95 million to net revenue from asset-based trading, our energy services business, and from transportation and commodity contracts acquired on favourable terms.

During the year, we took advantage of market inefficiencies and seasonal variations. In particular, our transportation and storage capacity gave us the flexibility to capitalize on weather events by allowing us to move gas to where it was needed most. We also held financial contracts that allowed us to capture trading profits around time and location spreads.

North American crude oil contributed $25 million to net revenue as varying degrees of backwardation (declining prices) in the forward price curve throughout the year allowed us to capitalize on calendar spreads. In addition, we took advantage of quality spreads and arbitrage opportunities to capture favourable price differences.

International crude oil contributed $24 million, three times higher than last year. Throughout the year, we successfully capitalized on the pricing of purchases relative to sales as we took advantage of backwardation in the forward price curve.

2003 vs 2002—Record net marketing revenue increased net income by $96 million

Marketing delivered record financial results growing their cash flow by 132% over 2002. This achievement was driven primarily by exceptional results from our gas marketing and trading group, supplemented by steady profits from our crude oil trading and marketing group.

Our natural gas group successfully positioned themselves to benefit from price differences between Western Canada and Eastern North America, and between summer and winter months. We also added transportation and storage capacity to our contract base. Added transportation capacity allowed us to take advantage of price differences between receipt and delivery points while added storage allowed us to take advantage of varying seasonal demand in the summer and winter months.

The continued exit of competitors from the market in 2003 enabled us to acquire contracts on favourable terms, including storage and transportation contracts and natural gas contracts.

COMPOSITION OF NET MARKETING REVENUE

(Cdn$ millions)	2004	2003
Trading Activities	133	148
Non-Trading Activities	22	21
Total Net Marketing Revenue	**155**	**169**

TRADING ACTIVITIES

In marketing, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes.

We account for all derivative contracts, not designated as hedges for accounting purposes, using mark-to-market accounting, and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is recorded as accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date.

We mark-to-market all derivative contracts not designated as hedges. The gain or loss is recorded in marketing and other income.

We value derivative trading contracts daily using:

- actively quoted markets such as the New York Mercantile Exchange and the International Petroleum Exchange; and
- other external sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.

Fair Value of Derivative Contracts

At December 31, 2004, the fair value of our derivative contracts not designated as hedges totalled $93 million (2003—$106 million). Below is a breakdown of this fair value by valuation method and contract maturity:

			Maturity		
(Cdn$ millions)	< 1 year	1-3 years	4-5 years	> 5 years	Total
Prices					
Actively Quoted Markets	5	(3)	-	-	2
From Other External Sources	43	40	9	(1)	91
Based on Models and Other Valuation Methods	-	-	-	-	-
Total	**48**	**37**	**9**	**(1)**	**93**

More than 50% of our unrealized fair value is for contracts settling in 2005. This helps reduce our risk.

More than 50% of the unrealized fair value relates to contracts that will settle in 2005. Contract maturities vary from a single day up to six years. Those maturing beyond one year are primarily from natural gas related positions. The relatively short maturity position of our contracts lowers our portfolio risk.

At December 31, 2004, we had $6 million of unrecognized gains on our derivative contracts designated as accounting hedges of the future sale of our gas inventory. These gains will be recognized in income when the inventory is sold. These contracts were valued from actively quoted markets and settle within 12 months.

We do not use option valuation methods to record income on transportation and storage contracts.

Changes in Fair Value of Derivative Contracts

(Cdn$ millions)	Contracts Outstanding at Beginning of Year	Contracts Entered into and Closed During Year	Contracts Entered into During Year and Outstanding at End of Year	Total
Fair Value at December 31, 2003	106	-	-	106
Change in Fair Value of Contracts	(26)	77	82	133
Net Losses (Gains) on Contracts Closed	(69)	(77)	-	(146)
Changes in Valuation Techniques and Assumptions[1]	-	-	-	-
Fair Value at December 31, 2004	**11**	**-**	**82**	**93**
Unrecognized Gains on Hedges of Future Sale of Inventory at December 31, 2004				6
Total Outstanding at December 31, 2004				**99**

Note:
1 Our valuation methodology has been applied consistently year-over-year.

Total Carrying Value of Derivative Contracts

(Cdn$ millions)	2004	2003
Current Assets	177	102
Non-Current Assets	91	63
Total Derivative Contract Assets	**268**	**165**
Current Liabilities	129	34
Non-Current Liabilities	46	25
Total Derivative Contract Liabilities	**175**	**59**
Total Derivative Contract Net Assets[1]	**93**	**106**

Note:
1 Does not include effective hedges. We recognize gains and losses on effective hedges in the same period as the hedged item.

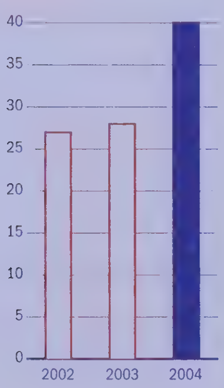
NON-TRADING ACTIVITIES

We enter into fee-for-service contracts related to transportation and storage, and increased our transportation capacity in 2003 and 2004.

We enter into fee-for-service contracts related to transportation and storage of third-party oil and gas. We also earn income from our power generation facility. We earned $22 million from our non-trading activities in 2004 (2003—$21 million).

In 2003 and 2004, we increased our transportation capacity and were paid to assume future obligations associated with the capacity. We included $53 million of deferred revenue on our balance sheet to recognize the liability associated with these obligations. This deferred revenue will be amortized to earnings as the capacity is used.

Chemicals Contribution to Income Before Taxes
(Cdn$ millions)



CHEMICALS

(Cdn$ millions)	2004	2003	2002
Net Sales	378	375	367
Sales Volumes (thousand short tons)			
Sodium chlorate	506	478	454
Chlor-alkali	403	396	375
Operating Profit[1]	105	95	100
Operating Margin[2]	28%	25%	27%
Chemicals Contribution to Income from Continuing Operations Before Income Taxes	40	28	27
Capacity Utilization	95%	95%	85%

Notes:
1 Total revenues less operating costs, transportation and other.
2 Operating profit divided by net sales.

2004 vs 2003—Higher chemicals operating profit increased net income by $10 million

Our chemicals business benefited from strong demand for bleaching chemicals in North and South America. Solid North American demand for chlor-alkali and sodium chlorate throughout 2004 resulted in strong pricing for our products. A stronger Canadian dollar lowered our sales by $15 million in 2004, as most of our sales are denominated in US dollars while our costs are primarily in Canadian dollars.

Solid demand for bleaching chemicals resulted in strong prices for our products in 2004.

We successfully completed the expansion of our Brandon, Manitoba plant in October, making it the largest sodium chlorate production facility in the world. This expansion minimizes our exposure to the rising electricity costs faced in other provinces, as Manitoba enjoys stable, regulated electricity markets. We expect further margin and cash flow improvement in 2005 as we produce more of our product from this low-cost plant.

At our Brazil plant, production improvements allowed us to take advantage of strong market demand. We are changing our electricity source for our facilities and expect to contract longer-term electricity supply for most of our requirements. We expect lower annual electricity costs in 2005 when these contracts are in place.

We are considering the sale of our chemicals business in 2005. Any such sale would reduce contributions from this business to our 2005 net income.

2003 vs 2002—Lower chemicals operating profit reduced net income by $5 million

Strong North American demand for chlor-alkali and sodium chlorate helped boost sales volumes and prices in 2003. In North America, we manufacture our products in Canada. Most of our sales, however, are into US markets. A stronger Canadian dollar lowered our operating profit by $13 million, as most of our sales are denominated in US dollars.

Higher natural gas prices in North America put pressure on electricity costs. To deal with these cost pressures, we idled our Taft plant, our highest electricity cost facility, and relocated the assets to Brandon. Our cost savings from idling the plant were offset by product we purchased from other suppliers to satisfy southeastern US customers.

CORPORATE EXPENSES

General and Administrative (G&A)[1]

(Cdn$ millions)	2004	2003	2002
General and Administrative Expense before Stock Based Compensation	206	176	150
Stock Based Compensation[2]	93	14	2
Total General and Administrative Expense	**299**	**190**	**152**

Notes:
1 Includes G&A from discontinued operations. See Note 11 to our Consolidated Financial Statements.
2 Includes tandem option plan, stock options for our US-based employees and stock appreciation rights.

2004 vs 2003—Higher costs reduced net income by $109 million

During the second quarter, our shareholders approved modifying our stock option plan to a tandem option plan, creating a one-time G&A expense of $82 million. Our tandem option obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. These obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding.

Modifying our stock option plan to a tandem option plan added a one-time $82 million charge to G&A in 2004.

Other G&A costs include increased variable incentive compensation in light of our record results, increased headcount due to increased capital investment, and higher regulatory compliance costs, including costs associated with our Sarbanes-Oxley internal control documentation project.

2003 vs 2002—Higher costs and lower recoveries reduced net income by $38 million

Approximately 75% of the G&A increase relates to higher variable compensation:

- Record 2003 results increased bonus compensation by $16 million; and
- Strong stock prices at year-end increased the value of our employee stock appreciation rights and related expense by $13 million.

The continued expansion of our marketing group also increased our staffing costs in 2003.

Interest

(Cdn$ millions)	2004	2003	2002
Interest[1]	194	212	212
Less: Capitalized	(51)	(43)	(31)
Net Interest Expense	**143**	**169**	**181**
Effective Rate	6.6%	7.2%	7.1%

Note:
1 Includes dividends on preferred securities. See Note 1(r) to our Consolidated Financial Statements.

Our effective rate dropped to 6.6% as we refinanced our preferred securities with lower-cost debt and repaid bonds. See page 53 for details on our capital structure.

2004 vs 2003—Lower interest expense increased net income by $26 million

In late-2003 and early-2004, we refinanced our preferred securities with lower-cost debt. We also repaid US$225 million of bonds in February 2004. The refinancing of our preferred securities and the repayment of the bonds reduced interest expense in 2004.

In December 2004, we drew US$1.5 billion on our acquisition credit facilities to assist the financing of our North Sea acquisition in the UK. This increased our interest expense by $5 million.

The strong Canadian dollar lowered our US-dollar denominated interest expense by $6 million.

We capitalized interest on our Syncrude Stage 3 expansion, the Long Lake Project in Canada, our Block 51 development in Yemen and our Buzzard development in the North Sea.

2003 vs 2002—Lower interest expense added $12 million to net income

The full year impact of our 30-year notes issued in March 2002, together with the refinancing of our preferred securities with lower-cost debt in November 2003 and the impact of a strong Canadian dollar on our US-dollar denominated interest expense kept our interest costs flat.

We capitalized interest on our Syncrude Stage 3 expansion and our Gunnison development project in the Gulf of Mexico.

Income Taxes

(Cdn$ millions)	2004	2003	2002
Current	248	214	207
Future	119	(73)	(44)
Total Provision for Income Taxes	**367**	**141**	**163**
Effective Rate	32%	20%	31%

See page 102 for breakdown of income taxes. We estimate our 2005 tax rate to be consistent with 2004.

2004 vs 2003—Effective tax rate increases from 20% to 32%

In 2004, a 1% reduction in Alberta's corporate income tax rate resulted in a $15 million recovery of future income taxes. The low effective tax rate for 2003 resulted from reduced federal tax rates for Canadian resource activities which generated a recovery of future income taxes of $76 million. The effective tax rate for 2005 is expected to be 33%.

Most of our current income taxes are cash taxes paid in Yemen. In 2004, these totalled $227 million (2003—$201 million; 2002—$207 million). In 2004 and 2003, federal and provincial capital taxes were payable in Canada. In both years, current income taxes also include alternative minimum tax in the United States.

2003 vs 2002—Effective tax rate declines from 31% to 20%

The low 2003 effective tax rate was due to reduced federal tax rates for Canadian resource activities. This resulted in a recovery of future income taxes of $76 million during the second quarter of 2003.

Other Income

(Cdn$ millions)	2004	2003	2002
Unrealized Mark-to-Market Gains on WTI Put Options	56	-	-
Gains (Losses) on Disposition of Assets	24	-	(8)
Foreign Exchange Gains (Losses)	(13)	6	(3)
Business Interruption Insurance Proceeds	10	12	-
Interest Income	12	9	7
Other	17	15	4
Total Other Income	**106**	**42**	-

We purchased WTI put options in the fourth quarter of 2004 to manage the commodity price risk exposure on part of our oil production in 2005 and 2006. These options are carried at fair value and an unrealized gain of $56 million was recognized in the fourth quarter as WTI forward prices declined late in the year.

Unrealized mark-to-market gains on our put options make up approximately 50% of other income. These options will be revalued quarterly.

Gains on the disposition of assets in 2004 resulted from selling minor oil and gas assets in Canada. There was no gain or loss on the 2003 sale of our southeast Saskatchewan properties as described in Note 11 to the Consolidated Financial Statements. The net loss in 2002 includes a gain of $13 million on the sale of our asphalt operation in Moose Jaw, Saskatchewan and a loss of $21 million on the sale of a non-operated property by our Canadian oil and gas business. The business interruption insurance proceeds received in 2004 and 2003 relate to damage sustained in the Gulf of Mexico during tropical storm Isidore and Hurricane Lili in the third and fourth quarters of 2002.

Foreign exchange losses in 2004 mainly relate to the impact of a stronger Canadian dollar on our US-dollar cash balances. Foreign exchange gains on our US-dollar debt portfolio are not recognized in our net income as our US-dollar debt has been designated as a hedge of our net investment in foreign operations. These gains are recorded on our balance sheet as cumulative foreign currency translation adjustments.

IMPACT OF FOREIGN EXCHANGE ON OPERATIONS

The strengthening Canadian dollar relative to the US dollar reduced cash flow from operating activities by $200 million and our net income by $105 million. This is because our foreign revenues and realized commodity prices, referenced in US dollars, were lower when translated to Canadian dollars. However, we benefit to the extent that our foreign operating costs and capital expenditures are also reduced when translated. In addition, most of our fixed-rate debt is denominated in US dollars so the Canadian dollar equivalent of this debt is reduced with a strengthening Canadian dollar. We have designated our US-dollar denominated debt as a hedge of our net investment in foreign operations. As a result, unrealized foreign exchange gains on the translation of this debt are not included in our net income. These unrealized gains are included as cumulative foreign currency translation adjustments on our balance sheet. The tax effect of unrealized foreign exchange gains on our US-dollar debt results in a decrease to our future income tax assets. This decrease in our future income tax assets is offset by a decrease to our cumulative translation adjustment account.

A stronger Canadian dollar negatively impacts our realized commodity prices, and positively impacts our US-dollar denominated fixed-rate debt, operating costs and capital expenditures.

OUTLOOK FOR 2005

In 2005, we plan to invest approximately $2.6 billion in capital projects, an increase of over $900 million compared to 2004, excluding acquisitions. Approximately 20% of this capital will be directed toward sustaining production and cash flow from our producing oil, gas and other assets in the short term. The majority, however, will be invested in longer cycle-time growth opportunities that we expect to begin contributing production and cash flow in 2006 and beyond. In 2005, our oil and gas capital program is expected to be invested as follows:

- 65% in new growth development projects;
- 18% in core assets to maintain existing production levels; and
- 17% in new growth exploration projects.

Details of our 2005 capital investment program are included in the Capital Investment section of the MD&A.

See page 32 for details of our 2005 capital program.

We plan to raise $1.5 billion in 2005 by selling assets which may include, among other things, our chemicals business and certain conventional Canadian oil and gas assets. The capital, cash flow and production guidance which follows does not take into account any dispositions.

Daily Production

Approximately 20% of our cash flow from core assets will be reinvested in those assets in 2005. This will deliver production before royalties of between 230,000 and 250,000 boe/d (170,000-185,000 after royalties) in 2005 before planned asset sales.

	2005 Estimated Production	
(mboe/d)	Before Royalties	After Royalties
Gulf of Mexico[1]	50 - 60	43 - 53
UK North Sea	14 - 18	14 - 18
Yemen	90 - 100	52 - 58
Canada[2]	52 - 56	40 - 44
Syncrude	16 - 18	16 - 17
Colombia	4 - 6	4 - 5
Total	**230 - 250**	**170 - 185**

Notes:
1 US natural gas production is estimated to comprise 46% of total US equivalent production in 2005.
2 Canadian natural gas production is estimated to comprise 44% of total Canadian equivalent production in 2005.

In 2005, we expect to modestly grow production after royalties and generate over $2 billion in cash flow from operating activities.

We expect our production after royalties to grow modestly in 2005, while we continue to invest in major development projects which are expected to come on stream in 2006 and beyond. Many of these have low or no royalties, lower costs and ultimately higher margins and returns than our current producing assets. This changing production mix is expected to improve profitability, even if oil prices trend somewhat lower.

Cash Flow and Sensitivities

We expect to generate over $2 billion in cash flow from operating activities in 2005 (before asset sales, site restoration and geological and geophysical expenditures), assuming the following:

WTI (US$/bbl)	40.00
NYMEX natural gas (US$/mmbtu)	6.50
US to Canadian dollar exchange rate	0.80

We have purchased put options on 60,000 bbls/d of our oil production in both 2005 and 2006. These options establish an average WTI floor price for this production of US$43.17/bbl in 2005 and US$38.17 in 2006. Changes in actual commodity prices and exchange rates impact our annual cash flow from operating activities as follows:

(Cdn$ millions)	
WTI–US$1 change above US$43.17	50
WTI–US$1 change below US$43.17	25
NYMEX natural gas–US $0.10 change	10
Exchange rate–$0.01 change	25

A US$1/bbl in WTI above $43/bbl will change cash flow from operating activities by $50 million.

In addition to strong cash flow from our oil and gas operations, we expect continued strong performance from our chemicals and marketing businesses in 2005. Our chemicals operations expect another year of solid stable cash flow and net income as we continue to see strong demand and pricing for our products. Our Brandon plant will provide lower cost operations. Our marketing group also anticipates another profitable year as they continue to maximize the value of their asset base.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

(Cdn$ millions)	2004	2003
Net Debt[1]		
Bank Debt	1,993	-
Public Senior Notes	1,813	2,214
Senior Debt	3,806	2,214
Subordinated Debt	553	594
Preferred Securities	-	281
Total Debt	4,359	3,089
Less: Cash and Cash Equivalents	(74)	(1,087)
Less: Non-Cash Working Capital[2]	(66)	(312)
Total Net Debt	4,219	1,690
Shareholders' Equity[3]	2,867	2,075

Notes:
1 Includes all of our debt and is calculated as long-term debt less net working capital.
2 Excludes current portion of long-term debt and short-term borrowings.
3 At January 31, 2005, there were 129,415,565 common shares and US$460 million of unsecured subordinated securities outstanding. These subordinated securities may be redeemed by issuing common shares at our option after November 8, 2008. The number of shares issuable depends on the common share price on the redemption date.

Net debt is long-term debt less working capital. We use it to monitor the strength of our balance sheet.

Net Debt

We use net debt as a key indicator of our leverage levels and to monitor the strength of our balance sheet. Our net debt levels are directly related to our operating cash flows, our capital investment activities and disposition programs. We ended the year with net debt at $4.2 billion, an increase of $2.5 billion over 2003 year-end levels. This reflects our North Sea acquisition on December 1, 2004, which was financed with US$1.5 billion of debt and US$600 million of cash on hand. Changes in net debt related to:

We financed the North Sea acquisition with US$600 million in cash and US$1.5 billion of debt.

(Cdn$ millions)	2004	2003
Capital Investments (including North Sea acquisition)	4,264	1,494
Cash Flow from Operating Activities	(1,607)	(1,405)
Excess of Capital Investment over Cash Flow	2,657	89
Dividends on Common Shares	52	40
Proceeds on Disposition of Assets	(34)	(293)
Issue of Common Shares (primarily exercise of employee stock options)	(124)	(73)
Foreign Exchange Translation of US-dollar Debt and Cash	(78)	(281)
Other	56	(240)
Increase (Decrease) in Net Debt	**2,529**	**(758)**

The increase in net debt has impacted our leverage metrics:

(times)	2004	2003	2002
Net Debt to Cash Flow from Operating Activities	2.6	1.2	2.0
Interest Coverage[1]	11.9	10.1	7.9

Note:
1 Earnings before interest, taxes, DD&A and exploration expense divided by interest expense (before capitalized interest).

Our business strategy is focused on value-based growth through full-cycle exploration and development, supplemented by strategic acquisitions when appropriate. To grow our company, we used leverage to develop the Masila project in Yemen in 1993, acquire Wascana in 1997 and acquire the remaining interest in Aspen in 2002. Each time, we exceeded our internal net debt to cash flow target band, however, we successfully brought our leverage back down once these projects began generating cash flow. In 2004, we again elevated our leverage levels as a result of our North Sea acquisition. We plan to sell $1.5 billion of assets in 2005 to reduce our leverage. Leverage is expected to be reduced further when our Buzzard and Long Lake projects come on stream and contribute cash flow in 2006 and 2007.

Change in Working Capital

(Cdn$ millions)	2004	2003	Increase/ (Decrease)
Cash and Cash Equivalents	74	1,087	(1,013)
Accounts Receivable	2,136	1,423	713
Inventories and Supplies	351	270	81
Accounts Payable and Accrued Liabilities	(2,416)	(1,404)	(1,012)
Other	(5)	23	(28)
	140	**1,399**	**(1,259)**

Cash and cash equivalents decreased by over $1 billion during the year as we:

- repaid US$225 million of senior debt in February;
- redeemed US$217 million of preferred securities in February; and
- paid US$600 million relating to our North Sea acquisition.

Increased payables and receivables reflect higher commodity prices and increased activity for our gas marketing business.

Accounts receivable and accounts payable increased, reflecting higher commodity prices and increased activity for our gas marketing business. We also acquired accounts receivable and accounts payable as part of our North Sea acquisition. Capital accruals were higher at year-end from our Buzzard and Long Lake development projects, and as a result of increased exploration activity in the Gulf of Mexico. Inventory levels in the marketing group were up at year-end given higher activity during the last part of 2004.

Liquidity

We manage our capital structure to maintain flexibility so we can fund our capital program through the commodity price cycles.

We generally rely on operating cash flows to fund capital requirements and provide liquidity. We build our opportunity portfolio to provide a balance of short-term, mid-term, and longer-term growth. Given the long cycle-time of some of our development projects and the volatility of commodity prices, it is not unusual, in any given year, for capital expenditures to exceed our cash flow. When this happens, we draw on available credit facilities, as we maintain significant undrawn committed credit facilities. From time to time, we access the capital markets to meet our financing needs. We also use various financial instruments to minimize our exposure to fluctuations in foreign exchange and commodity prices. For example, we purchased WTI put options for 2005 and 2006 to mitigate liquidity risk and reduce cash flow volatility. Overall, we manage our capital structure to maintain flexibility so we can fund our capital programs throughout the highs and lows of the price cycles inherent in the oil and gas business.

The following table shows how we use our cash flow from operating activities to fund our investing activities. When our operating cash flows exceed our investment requirements, we generally pay down debt. We generally borrow to fund investment requirements in excess of our operating cash flows.

(Cdn$ millions)	2004	2003	2002	2001	2000
Cash Flow from Operating Activities	1,607	1,405	1,250	1,496	1,261
Cash Flow from Investing Activities	(4,013)	(1,219)	(1,569)	(1,469)	(897)
	(2,406)	186	(319)	27	364
Cash Flow from Financing Activities	1,426	1,006	329	(100)	(359)
	(980)	**1,192**	**10**	**(73)**	**5**

In 2000, strong commodity prices allowed us to generate sufficient cash flow to buy back 20 million common shares. In 2001 and 2002, we began to invest significantly in two deep-water Gulf of Mexico projects (Aspen and Gunnison), our Syncrude expansion and our Long Lake Project. In 2001, we used our cash flow and in 2002, we accessed the public debt markets to fund this investment activity. In 2003, Aspen contributed significantly to our cash flow and in late-2003, we pre-funded debt repayments by raising over $1 billion in senior and subordinated debt. We used these funds in 2004 to repay higher cost debt, and coupled with our acquisition credit facilities, acquired the North Sea assets.

Future Liquidity

Our future liquidity is primarily dependent on cash flows generated from our operations, our capital programs and the flexibility of our capital structure. Assuming WTI of US$40/bbl in 2005, we expect our 2005 capital investment program and dividend requirements to exceed our cash flow by almost $600 million. We are planning to raise $1.5 billion from asset dispositions in 2005 and we expect to use the proceeds to fund the shortfall and to retire debt.

Our cash flow is sensitive to changes in commodity prices and exchange rates. For 2005, we expect to generate cash flow of over $2.0 billion (before asset sales, remediation and geological and geophysical expenditures) assuming the following:

WTI (US$/bbl)	40.00
NYMEX natural gas (US$/mmbtu)	6.50
US to Canadian dollar exchange rate	0.80

Changes in commodity prices and exchange rates will impact our cash flow and our borrowing requirements. The impact of a variance in any one of the above assumptions on our cash flow is described in the Outlook for 2005 section of the MD&A.

See page 52 for our commodity price and foreign exchange sensitivities.

We are in the midst of developing a number of major projects. Much of our planned capital spending over the next three years will be allocated to Long Lake, the Buzzard project in the North Sea and Syncrude Stage 3.

Our anticipated spending on these projects in 2005, 2006 and 2007 is as follows:

(Cdn$ millions)	
2005	1,388
2006	1,125
2007	415
Total Capital Investment	**2,928**

Given our reliance on cash flows to fund these projects, we executed a cash flow protection strategy using WTI crude oil put options in late-2004. These put options provide us with an annual average WTI floor price of US$43.17/bbl in 2005 and US$38.17 in 2006 on 60,000 bbls of oil per day each year. This strategy reduces the downside risk to our future cash flows in 2005 and 2006 when our capital requirements are high, yet still allows us to realize price upside.

Our put options reduce downside price risk in 2005 and 2006 yet enable us to realize price upside.

Our Buzzard project creates foreign currency exposure as a portion of the capital costs are denominated in British pounds and Euros. In order to reduce our exposure to fluctuations in these currencies, we purchased foreign currency call options in early-2005 which effectively set a ceiling on most of our British pound and Euro spending exposure from March 2005 through to the end of 2006.

While these development projects lack exploration risk, they are subject to execution risk, the risk of higher than anticipated spending or delayed start-up. We minimize the financial impact of these risks by maintaining undrawn committed credit facilities. These facilities extend beyond the expected start-up dates of our Syncrude expansion, our Long Lake Project and the Buzzard development. Undrawn amounts on these facilities at December 31, 2004 were almost $1.6 billion. We also have a committed credit facility available until late-2007 which may be used to finance the development and operation of our North Sea assets including Buzzard. At December 31, 2004, US$500 million was available on this facility.

In addition to our operating cash flows and our sizeable undrawn committed credit facilities, we have a US$1 billion shelf registration available in the US and Canada to allow us to access the debt capital markets.

If required, we have more than $2 billion in undrawn credit facilities and a US$1 billion shelf registration in the US and Canada to access debt markets.

At December 31, 2004, the average term to maturity of our long-term debt was 11.9 years. We have the following debt maturities in the next five years:

(Cdn$ millions)	2005	2006	2007	2008	2009
Acquisition Credit Facilities	903	-	903	-	-
Term Credit Facilities[1]	-	-	22	65	-
Debentures	-	93	-	-	-
Medium Term Notes	-	-	150	125	-
Total	**903**	**93**	**1,075**	**190**	-

Note:
1 Undrawn amounts of $0.4 billion available until 2008 and $1.2 billion available until 2009.

We may retire our debt maturities with a portion of the proceeds from planned asset sales or we may refinance the maturities with longer-term debt. In addition, we have sufficient capacity on our term credit facilities to refinance a portion of these maturities, if need be.

In light of our cash flow streams, our commodity price and foreign exchange hedging strategies and our current levels of liquidity, we expect to have no difficulties funding our planned capital programs, dividend requirements and debt repayments or in meeting the obligations that arise from our day-to-day operations.

We expect to declare common share dividends of $0.40 per common share in 2005.

In 2004, we declared common share dividends of $0.40 per common share (2003—$0.325, 2002—$0.30). We expect to declare common share dividends of $0.40 per common share in 2005.

Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities. These obligations and commitments are considered in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

Our long-term debt accounts for almost 70% of our contractual obligations and commitments.

		Payments			
(Cdn$ millions)	Total	<1 year	1-3 years	4-5 years	>5 years
Short and Long-Term Debt	4,359	1,003	1,168	190	1,998
Interest on Short and Long-Term Debt	3,789	221	401	278	2,889
Operating Leases[1]	248	31	53	45	119
Energy Commodity Contracts	175	129	42	4	-
Transportation and Storage Commitments[1]	780	366	200	84	130
Work Commitments and Purchase Obligations[2]	1,794	958	832	4	-
Asset Retirement Obligations	770	47	32	42	649
Other	5	1	1	1	2
Total	**11,920**	**2,756**	**2,729**	**648**	**5,787**

Notes:
1 Payments for operating leases and transportation commitments are deducted from our cash flow from operating activities.
2 The vast majority of these payments relate to work commitments cancellable at our option without penalties or additional fees.

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur.

- Short and long-term debt amounts are included on our December 31, 2004 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and our processing agreement with Shell that allows our Aspen production to flow through Shell's processing facilities at the Bullwinkle platform. The terms of the processing agreement give Shell an annual option to take payment in cash or in kind. For 2005, Shell has elected to take payment in kind so the 2005 obligation has been excluded from this table. Instead, it is shown as a royalty and excluded from reserves and production.
- Energy commodity contracts include the purchase and sale of physical quantities of oil and natural gas, and financial derivatives used to manage our exposure to commodity prices. For contracts where the price is based on an index, the amount is based on forward market prices at December 31, 2004. For certain contracts, we may net settle rather than pay cash.
- Our marketing operation manages various natural gas transportation and storage commitments on behalf of our Canadian oil and gas business and a number of third-party customers.

- Work commitments include non-discretionary capital spending related to drilling, seismic, construction of facilities and other development commitments in our international operations, at Long Lake ($274 million), the Buzzard project in the North Sea ($1 billion) and at Block 51 ($189 million). The timing of certain payments is difficult to determine with certainty. The table has been prepared using our best estimates; the remainder of our 2005 capital investment is discretionary.
- We have $770 million of undiscounted asset retirement obligations. As of December 31, 2004, the estimated fair value ($468 million) of these obligations has been provided for in our consolidated financial statements (including $47 million of current liabilities). The timing of any payments is difficult to determine with certainty and the table has been prepared using our best estimates.
- We have unfunded obligations under our defined benefit pension and post retirement benefit plans of $46 million and our share of Syncrude's unfunded obligation is $41 million. Our $46 million obligation includes $34 million that is unfunded as a result of statutory limitations. These obligations are backed by irrevocable letters of credit. During 2004, we contributed $6 million to our defined benefit pension plan. We currently are not anticipating any funding requirements in 2005 for our defined benefit pension plan.
- We have excluded our unvested obligations on our stock option and stock appreciation rights programs as the amount and timing of the cash payments are indeterminable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and our capital expenditures for 2005.
- We have excluded our future income tax liabilities as the amount and timing of any cash payments for income taxes are based primarily on taxable income for each discrete fiscal year in the various jurisdictions in which we operate.

From time to time we enter into contracts that require us to indemnify parties against possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated, therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. Our Risk Management Committee actively monitors our exposure to the above risks and obtains insurance coverage to satisfy potential or future claims as necessary. We believe these matters would not have a material adverse effect on our liquidity, financial condition or results.

Credit Ratings

Currently, our senior debt is rated BBB- by Standard & Poor's (S&P), Baa2 by Moody's Investor Service, Inc. and BBB by Dominion Bond Rating Service (DBRS). In addition, S&P currently rates our outlook as stable while Moody's and DBRS have a negative outlook. Our strong financial results, ample liquidity and financial flexibility continue to support our credit rating.

Credit Rating:
S&P: BBB-
Moody's: Baa2
DBRS: BBB

Financial Assurance Provisions in Commercial Contracts

The commercial agreements our marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require posting collateral if a buyer's credit rating drops below investment grade, indicating their creditworthiness has deteriorated. Based on the contracts in place and commodity prices at December 31, 2004, we would be required to post collateral of approximately $780 million if we were downgraded to non-investment grade. These obligations are reflected on our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Our committed undrawn credit facilities available for general corporate purposes of $1.6 billion adequately cover any potential collateral requirements. Just as we may be required to post collateral in the event of a downgrade below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral with us if they are downgraded to non-investment grade.

Off-Balance Sheet Arrangements

None.

Contingencies

We have no contingencies that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. See Note 12 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference for a discussion of our contingencies.

BUSINESS RISK MANAGEMENT

Our operations are exposed to various risks, some of which are common to others in our industry and some of which are unique to our operations. We attempt to mitigate the risks to an acceptable level but many of these risks are beyond our control so we cannot provide any assurances that they will not result in negative financial consequences.

Competition

The oil and gas industry is highly competitive, particularly in the following areas:

- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include major integrated oil and gas companies and numerous other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers.

The pulp and paper chemicals market is also highly competitive. Key success factors are:

- price;
- product quality; and
- logistics and reliability of supply.

We are one of the largest producers of sodium chlorate in North America and have continent-wide supply capability.

Competitive forces may result in shortages of prospects to drill, services to carry out exploration, development or operating activities, and infrastructure to produce and transport production. It may also result in an oversupply of crude oil and natural gas. Each of these factors could have a negative impact on costs and prices and, therefore, our financial results.

Operational Risks

Acquiring, developing and exploring for oil and natural gas involves many risks. These include:

- encountering unexpected formations or pressures;
- premature declines of reservoirs;
- blow-outs, well bore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids; and
- environmental risks.

We operate two facilities that are located in close proximity to populated areas, and each processes materials of potential harm to the local populations. At Balzac, just north of Calgary, we operate a gas plant that processes sour gas. In North Vancouver, we operate a chlor-alkali plant that produces chlorine. We have undertaken several initiatives to mitigate the potential risks associated with these operations. First, we have instituted operating procedures that have allowed each to be verified as Responsible Care® facilities by the Canadian Chemical Producers Association, with our Balzac plant being the first oil and gas facility in the world to be so certified. Also, at North Vancouver, we conducted extensive quantified risk analysis complying with guidelines of the Major Industrial Accidents Council of Canada (MIACC). As a result, substantial changes to operating and inventory practices were implemented. The risk is now consistent with Responsible Care® and MIACC guidelines. Also, at both facilities, we work with surrounding communities to keep them informed of our operations and have invited them to tour our facilities. Finally, we continually work with local municipalities to maintain appropriate emergency response and evacuation plans in the event of an accidental release of chemicals from the facilities.

Although we maintain insurance according to customary industry practice, we may not be fully insured against all of these risks. Losses resulting from the occurrence of these risks may have a material adverse impact on our financial results.

Offshore Operations

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. When possible, we take precautionary measures of temporarily shutting-in production, de-manning facilities and ceasing drilling operations. We carry insurance to compensate us for physical damage and business interruption, subject to normal deductions, resulting from such weather conditions.

Our operations in the Gulf of Mexico have been suspended, from time to time, due to hurricanes or tropical storms. While operations are generally restored quickly and production losses are not material, we have had one instance in the last five years where production was suspended for an extended period of time and substantial damage to facilities was incurred. In 2002, our facilities at Eugene Island 295 were damaged during Hurricane Lili. Production from this field was suspended for about four months while temporary production facilities were put in place. During this period, production volumes were reduced by approximately 2,500 boe/d. Production was restored at a reduced rate through temporary facilities for approximately six months while installation of new permanent facilities was completed. It is estimated that volumes were reduced by approximately 1,800 boe/d during this period. There was no significant financial impact after business interruption and property insurance claims.

Uncertainty of Reserves Estimates

Our future crude oil and natural gas reserves and production, and therefore our operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves will be impaired.

Over the past three years, we experienced net negative revisions of 337 million boe to our proved reserves (including Syncrude and before royalties). This includes 239 million boe related to changes in year-end prices, of which 246 million boe relates to the write-off of the reserves at our Long Lake oil sands project as a result of low bitumen prices at the end of 2004. Positive price revisions of 7 million boe related primarily to our Canadian heavy oil properties. The remaining negative revisions of 98 million boe, representing about 12% of worldwide proved reserves, occurred primarily on our producing properties in Canada and Yemen. In Canada, the majority of the negative revisions of 64 million boe occurred in 2003 as a result of an ongoing assessment of the future production profiles of our properties and a reduction of proved undeveloped reserves based on drilling results and updated geological mapping. In Yemen, the negative revisions of 37 million boe occurred largely in 2003 and 2004 and resulted primarily from lower-than-expected production performance, drilling results and updated geological mapping.

About two-thirds of the 98 million boe of net negative revisions were recognized as proved reserves based on projected future production performance of producing properties. These projections considered historical performance and expected future changes in production using all available engineering and geologic data. However, subsequent production performance did not meet our projections due to such factors as sand production, steeper than expected declines due to higher water cuts and the drilling of some infill locations which proved to have already been swept. The remainder of the reserves were recognized as proved undeveloped reserves based on production performance, well control and geologic mapping using seismic and other data. Lower than expected production, greater sweep efficiencies, and unsuccessful drilling caused us to revise our proved reserves estimates downward.

Under SEC rules, we recognize our oil sands as bitumen reserves. As a result, we expect price-related revisions, both positive and negative, to occur in the future as the economic producibility of our bitumen and heavy oil reserves are sensitive to year-end prices. In particular, since we recognize our oil sands as bitumen reserves and they are related to one project, all or none of the reserves will likely be considered economic depending on the year-end prices of bitumen, diluent and natural gas. The impact of year-end prices on our heavy oil reserves is expected to be immaterial.

Increased Leverage

Our overall indebtedness has increased as a result of acquiring the North Sea assets. Additional borrowings may be necessary to fund the field development plan for the Buzzard field as well as for the development of the Long Lake Project. While we believe that our overall indebtedness can be reduced through proceeds from the disposition of non-core assets, no assurance can be given that we will be able to implement such transactions.

Heavy Oil Operations

Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also yields a lower price relative to light oil and gas, as a smaller percentage of high-value petroleum products can be refined from heavy oil. As a result, our heavy oil operations are exposed to the following risks:

- additional costs may be incurred to purchase diluent to transport heavy oil;
- there could be a shortfall in the supply of diluent which may cause its price to increase; and
- the market for heavy oil is more limited than for light oil making it more susceptible to supply and demand fundamentals which may cause the price to decline.

Any one or combination of these factors could cause some of our heavy oil properties to become uneconomic to produce and/or result in negative reserve revisions.

Additional risk factors relating to our Long Lake oil sands project are provided under "Risk Factors Relating to Long Lake".

Risk Factors Relating to Long Lake

Our Long Lake Project is planned as a fully integrated production, upgrading and co-generation facility. We intend to use Steam Assisted Gravity Drainage (SAGD) technology to recover bitumen from oil sands. As designed, the bitumen will be partially upgraded using the proprietary OrCrude™ process, followed by conventional hydrocracking to produce a sweet, premium synthetic crude oil. The OrCrude™ process also yields liquid asphaltines that will be gasified into a syngas. This syngas will be used as a fuel source for the SAGD process, a source of hydrogen for use in the upgrading process, and to generate electricity through a co-generation facility.

We have a 50% working interest in this project, and our share of the construction cost is estimated to be $1.75 billion ($3.5 billion gross). Given the higher initial investment and operating costs to produce and upgrade bitumen, the payout period for the project is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

Risks associated with our Long Lake oil sands project include the following:

STATUS OF THE LONG LAKE PROJECT

The Long Lake Project is currently in the construction stage. There is a risk that actual costs may be higher than expected or that the project may not be completed on time or at all due to many factors, including:

- construction performance falling below expected levels of output or efficiency;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- inability to attract sufficient numbers of qualified workers;
- design errors;
- contractor or operator errors;
- non-performance by third-party contractors;
- changes in project scope;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- breakdown or failure of equipment or processes;
- violation of permit requirements;
- catastrophic events such as fires, earthquakes, storms or explosions; and
- disruption in the supply of energy.

Actual costs to construct and develop the project will vary from our estimates, and such variances may be significant. Our estimate of the cost associated with developing the Long Lake Project has been developed with an expected range of accuracy of approximately +/- 15%. In the formative stage of the project, our capital cost estimate was approximately $2.3 billion (gross). After completing further project definition, engineering and reviewing pilot results, we changed the scope of the project to include co-generation facilities, planned for certain redundancies within the upgrader, and applied more conservative estimates to labour productivity. As a result, the capital cost estimate at the time of our Board's sanctioning the project in February 2004 was $3.4 billion (gross). Our current capital cost estimate for completing the project is $3.5 billion (gross) reflecting the acceleration of drilling of an additional well pad consisting of 13 well pairs to ensure certainty and reliability of bitumen production at the commencement of upgrader operations.

SAGD BITUMEN RECOVERY PROCESS

SAGD has been used in Western Canada to increase recoveries from conventional heavy oil reservoirs for over a decade. However, application of SAGD to the in-situ recovery of bitumen from oil sands is relatively new. Most of the SAGD oil sands applications to date have been pilot projects and the process is in the early stages of application in commercial oil sands projects.

Our estimates for performance and recoverable volumes for the Long Lake Project are based primarily on our three well-pair SAGD pilot and industry performance from SAGD operations in the McMurray formation in the Athabasca oil sands. Using this data, our assumptions included average well-pair productivity of 900 bbls/d of bitumen and a steam-to-oil ratio of 2.5. We commenced steaming the reservoir for our SAGD pilot in May 2003 and commenced production in September 2003. The pilot is currently producing at a rate of about 600 barrels of bitumen per day per well-pair and a steam-to-oil ratio of about 3.5. Since September 2003, the pilot has recovered less than 2% of the original bitumen in place. While we expect actual performance to improve as the steam chamber grows in the reservoir, there can be no assurance that our SAGD operation will produce bitumen at the expected levels or steam-to-oil ratio. If the assumed production rates or steam-to-oil ratio are not achieved, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity and/or purchase natural gas for additional steam generation. These could have a significant adverse impact on the future activities and economic return of the Long Lake Project.

BITUMEN UPGRADING PROCESS

The proprietary OrCrude™ process we are using to upgrade raw bitumen to synthetic crude will be the first commercial application of the process although we have operated it in a 500 bbls/d demonstration plant. All the individual components of the technology used in this process are currently used in commercial applications around the world, however, there can be no assurance that the commercial upgrader being constructed at Long Lake will achieve the same or similar results as the demonstration plant or the results which are forecast. If we are unable to upgrade the bitumen for any reason we may decide to sell it as bitumen without upgrading it, which would expose us to the following risks:

- the market for bitumen is limited;
- additional costs would be incurred to purchase diluent for blending and transporting bitumen;
- there could be a shortfall in the supply of diluent which may cause its price to increase;
- the market price for bitumen is relatively low reflecting its quality differential; and
- additional costs would be incurred to purchase natural gas for use in generating steam for the SAGD process since we would not be producing syngas from the upgrading process.

These factors could have a significant adverse impact on the future activities and returns of the Long Lake Project.

If any of these factors arise, our operating costs would increase and our revenues would decrease from those we have assumed. This would cause a material decrease in expected earnings from the project and the project may not be profitable under these conditions.

At December 31, 2004, a shortage of diluent caused the price of diluent products to rise substantially above prices seen in the past. These conditions could be repeated in the future as the demand for diluents increases with the expected increase in production of bitumen from the Canadian oil sands.

DEPENDENCE ON OPTI CANADA

We are undertaking the Long Lake Project jointly with OPTI Canada (OPTI) pursuant to a joint venture agreement governing the construction, ownership and joint operation of the project. The agreement provides for the creation of a management committee that is responsible for the supervision and direction of the management and operation of the project, the supervision and control of the operators and all other matters relating to the development of the project. If our interest in any element of the project falls below 25%, OPTI may be able to make decisions respecting that element without our input, which may adversely affect our operations.

DEPENDENCE UPON PROPRIETARY TECHNOLOGY

The success of the project and our investment in the project depends to a significant extent on the proprietary technology of OPTI and proprietary technology of third parties that has been, or is required to be, licensed by OPTI. OPTI currently relies on intellectual property rights and other contractual or proprietary rights, including (without limitation) copyright, trademark laws, trade secrets, confidentiality procedures, contractual provisions, licenses and patents, to secure the rights to utilize its proprietary technology and the proprietary technology of third parties. OPTI may have to engage in litigation in order to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of the patents or proprietary rights of third parties. This kind of litigation can be time-consuming and expensive, regardless of whether or not OPTI is successful. The process of seeking patent protection can itself be long and expensive, and there can be no assurance that any currently pending or future patent applications of OPTI or such third parties will actually result in issued patents, or that, even if patents are issued, they will be of sufficient scope or strength to provide meaningful protection or any commercial advantage to OPTI. Furthermore, others may develop technologies that are similar or superior to the technology of OPTI or such third parties or design around the patents owned by OPTI and/or such third parties. There is also a risk that OPTI may not be able to enter into licensing arrangements with third parties for the additional technologies required for the possible further expansion of the Long Lake upgrader.

OPERATIONAL HAZARDS

The operation of the project will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We may not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that our insurance will be sufficient to cover any such casualty occurrences or disruptions. The project could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the project and on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading the recovered bitumen into synthetic crude oil and other products involve particular risks and uncertainties. The project is susceptible to loss of production, slowdowns, or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

The Long Lake SAGD operation and upgrader will process large volumes of hydrocarbons at high pressure and at high temperatures and will handle large volumes of high-pressure steam. Equipment failures could result in damage to the project's facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Certain components of the Long Lake Project will produce sour gas, which is gas containing hydrogen sulphide (H_2S). Sour gas is a colourless, corrosive gas that is toxic at relatively low levels to plants and animals, including humans. The project will include integrated facilities for handling and treating the sour gas, including the use of gas sweetening units, sulphur recovery systems and emergency flaring systems. Failures or leaks from these systems or other exposure to sour gas produced as part of the project could result in damage to other equipment, liability to third parties, adverse effect to humans, animals and the environment, or the shut down of operations.

The Long Lake Project will produce carbon dioxide emissions. Carbon dioxide is a greenhouse gas that will be regulated by the Kyoto Protocol, which is expected to come into effect in Canada in 2008. We will be required to purchase carbon dioxide credits in connection with these emissions, which we have budgeted at approximately $0.20/bbl of oil produced. If the cost of carbon dioxide credits reaches the Canadian cap, our actual cost would increase to approximately $0.40/bbl of oil produced.

ABORIGINAL CLAIMS

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of Western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the project and on us.

COMPETITION

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of oil interests and the distribution and marketing of petroleum products. The Long Lake Project competes with other producers of synthetic crude oil blends and other producers of conventional crude oil. Some of the conventional producers have lower operating costs than the project is anticipated to have. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than OPTI and us have announced plans to enter the oil sands business and begin production of synthetic crude oil, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

Concentration of Producing Assets

A portion of our production is generated from highly productive individual wells or central production facilities. Examples include:

- central processing facility, oil pipeline, and export terminal at our Yemen operations;
- Gunnison SPAR production platform in the Gulf of Mexico;
- highly productive Aspen wells tied-in to a third-party processing facility in the Gulf of Mexico; and
- Scott production platform in the North Sea.

As significant production is generated from each of these assets, any single event causing an interruption to these operations could result in the loss of production. We carry insurance to compensate us for physical damage and business interruption arising from most circumstances but it does not provide for losses arising from equipment failures.

Coal Bed Methane

Coal bed methane (CBM) is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by the coal itself rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in pressure in the coal. If the coal is water saturated, water generally needs to be extracted to reduce the pressure and allow gas production to occur. CBM wells typically have lower producing rates and reserves per well than conventional gas wells, although this varies by area. CBM fields are likely to require between two and eight gas wells per section to efficiently extract the natural gas. Regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain.

We are testing the feasibility of gas production from the Mannville coals in the Fort Assiniboine region of Alberta. These coals are deeper than other producing CBM projects and are water saturated. These projects require significant up-front capital investment in the form of land acquisition and drilling and completion costs. A significant period of time may be required to sufficiently de-water the coals to determine if commercial production is feasible. As a result, we may have to invest significant capital in CBM assets before they achieve commercial rates of production. The wells may never achieve commercial rates of production as there are no commercially proven Mannville CBM projects in operation.

CBM projects in some areas of the United States have had negative public reaction due to certain water disposal practices. In Canada, as in the United States, water disposal practices are regulated to ensure public safety and water conservation. Nevertheless, negative public perception around CBM production could impede our access to the resource.

Commitments to Projects Under Development

We have significant commitments in connection with various development activities currently underway. The Syncrude Stage 3 expansion is currently 74% complete and is expected to commence production in mid-2006. Development and construction activities on the Buzzard field are approximately 60% complete and Buzzard is expected to commence production in late-2006. Detailed project engineering on our Long Lake SAGD and upgrading project near Fort McMurray, Alberta is currently approximately 60% complete. Bitumen production from the Long Lake Project is expected to be achieved in the second half of 2006 and the first commercial production of upgraded synthetic crude oil is expected to be achieved in mid-2007. Our combined capital commitments for these projects are anticipated to be $1,388 million in 2005 and $1,125 million in 2006. In these projects, we are exposed to the possibility of cost overruns, which may be significant, and/or delays in commencement of commercial production.

Political Risk

We operate in numerous countries, some of which may be considered politically and economically unstable. Our operations and related assets are subject to the risks of actions by governmental authorities, insurgent groups or terrorists. We conduct our business and financial affairs to protect against political, legal, regulatory and economic risks applicable to operations in the various countries where we operate. However, there can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

In particular, our operations in Yemen expose us to potential material adverse financial consequences. In 2004, Yemen accounted for $415 million or 52% of our net income and this is expected to decline somewhat in 2005 as production declines on Masila are partially offset by production from completion of development activities on Block 51.

Our Masila operations are important to Yemen, providing 50% of the country's oil production. We are a responsible member of the Yemeni community; we build relationships with its citizens and involve them in key decisions that impact their lives. We also ensure that they benefit from our presence in their country beyond the revenue they receive from the production we operate. Our strong relationship with the people and Government of Yemen has allowed us to operate there without interruptions for almost 15 years and we anticipate this continuing.

Our practices have enabled us to operate successfully, not only in Yemen, but also in other parts of the world. We have developed excellent practices to manage the risks successfully.

Environmental Risk

Environmental risks inherent in the oil and gas and chemicals industries are becoming increasingly sensitive as related laws and regulations become more stringent worldwide. Many of these laws and regulations require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the disposal or release of specified substances.

We manage our environmental risks through a comprehensive and sophisticated Safety, Environmental and Social Responsibility (SESR) Management System that meets or exceeds ISO14001 criteria and those of similar management systems. Overall guidance and direction is provided by the SESR Committee of the Board of Directors. In addition, senior management, including the CEO and CFO, regularly meets with SESR management to review and approve SESR policies and procedures, provide strategic direction, review performance and ensure that corrective action is taken when necessary. We develop and implement proactive and preventative measures designed to reduce or eliminate future environmental liabilities, we are prudent and responsible in our management of existing environmental liabilities, and we continuously seek opportunities for performance improvement. We also maintain an ongoing awareness of external trends, demands, commitments, events or uncertainties that may reasonably have a material effect on revenues from continuing operations. These actions provide assurance that we meet or exceed appropriate environmental standards worldwide.

- At December 31, 2004, $468 million ($770 million, undiscounted) has been provided in the Consolidated Financial Statements for future asset retirement costs, relating to our oil and gas, Syncrude and chemicals facilities.
- During 2004, we increased our asset retirement obligations by $146 million (2003—$6 million) to reflect new obligations incurred or acquired.
- Actual site remediation expenditures for the year were $31 million (2003—$20 million). We anticipate actual site remediation expenditures in 2005 to approximate $47 million primarily in Australia and Nigeria.
- We perform periodic internal and external assessments of our operations and adjust our estimates and retirement obligations accordingly.
- During 2002, we conducted an external audit of our management systems for safety, environment and social responsibility issues. Overall, the review was positive and the few minor recommendations for improvement were implemented.
- During 2003 and 2004, we conducted an external operational audit and confirmed that our management systems for safety, environment and social responsibility issues were being followed.

Climate Change

The Kyoto Protocol comes into force on February 16, 2005 following Russia's delivery of its ratification instrument on November 18, 2004. Canada had previously ratified the Kyoto Protocol in December 2002. Canada committed in Kyoto in 1997 to an emission reduction of 6% below 1990 levels during the First Commitment period (2008 to 2012). Economic modeling studies have shown that if emission reductions are met through domestic action in Annex I countries alone, there will be severe negative impacts to those countries' economies, and in particular those such as Canada whose economies are resource and energy intensive. The US government's decision to withdraw from the Kyoto Protocol has serious implications for Canada in the context of a continental or hemispheric energy market.

The Canadian government has addressed the uncertainty associated with ratification and implementation of the Kyoto Protocol by providing the oil and gas sector with limits on cost (a cap of $15/tonne) and volume (a cap of 55 megatonnes for large industrial emitters) as well as its position on long-term, high capital-cost projects. In addition, emission reductions for oil and gas producers are expected to be capped at levels that are 15% lower than business as usual levels. However, the government has yet to enact national legislation that will detail the obligations of Canadian industry with respect to emission reduction and management, and it remains uncertain at this time when those obligations will be determined. The financial markets have viewed these developments favourably and have issued various analyses in the aftermath of these announcements indicating that implementation of Green House Gas (GHG)-related legislation should not adversely affect the development of new energy projects such as the oil sands.

For years, we have been assessing the impact of climate change developments on our various business interests. As a Canadian-based international oil and gas exploration and production company, we have worked closely with the Canadian Clean Development Mechanism/Joint Implementation Office of the Department of Foreign Affairs and International Trade to ensure that Canadian companies get access to low-cost/high-quality carbon offset investments. As well, we continue to work closely with the Canadian and Alberta governments to assess the impact of domestic regulatory options and provide information on our business to assist governments in their policy deliberations. We maintain a wide range of business contacts to ensure that a full slate of options is available to us in order to meet the obligations that may be imposed by future legislation.

We have created a senior management committee (The Climate Change Steering Group) to: consider national and international developments; hear from leading experts with respect to science, business and risk issues; and, consider investment opportunities. We have voluntarily reduced direct GHG emissions by almost two million tons of CO_2 equivalent since we started reporting in 1996. As well, progress has been made toward reduction of our energy inputs per unit of production.

We have entered into discussions with the management of several GHG investment pools and we continue to evaluate the opportunities associated with biological and geological sequestration of CO_2 and the capture of methane from landfills. We continuously review the feasibility of new and ongoing projects with respect to current social, political and economic factors and will continue to take into account policy and requirements with respect to GHG when conducting these reviews.

We are committed to the principles of full disclosure and we keep our stakeholders apprised of how these issues affect us. Since emission levels applicable to our business operations have not been determined and there are no reliable estimates of the costs of achieving those levels, premature disclosure would be speculative and any financial estimates would be based on arbitrary assumptions of emission levels. However, Canadian government assurances of cost and volume limits suggest that incremental risks and liabilities attributable to addressing climate change policies are manageable. Any indirect risks and liabilities attributable to GHG are too remote and unquantifiable at this time.

CRITICAL ACCOUNTING ESTIMATES

As an oil and gas producer, there are a number of critical estimates underlying the accounting policies we apply when preparing our Consolidated Financial Statements. These critical estimates are discussed below.

Oil and Gas Accounting—Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas properties.

The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data.

To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements.

Reserve estimates for each property are prepared at least annually by the property's reservoir engineer. They are reviewed by engineers familiar with the property and by divisional management. An Executive Reserves Committee, including our CEO, CFO and Board-appointed internal qualified reserves evaluator, meet with divisional reserves personnel to review the estimates and any changes from previous estimates.

The internal qualified reserves evaluator assesses whether our reserves estimates and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein, included in the Supplementary Financial Information, have been prepared in accordance with our reserve standards. His opinion stating that the reserves information has, in all material respects, been prepared according to our reserves standards is included in an exhibit to this Form 10-K.

We also have at least 80% of our reserve estimates audited annually by independent qualified reserves consultants. Given that the reserves estimates are based on numerous assumptions and interpretations, differences in estimates prepared by us and an independent reserves consultant are resolved when the differences are greater than 10%.

The Board of Directors has established a Reserves Review Committee (Reserves Committee) to assist the Board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas reserves and related disclosures. The Reserves Committee is comprised of three or more directors, the majority of whom are independent, and each being familiar with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, results and related disclosures. The Reserves Committee appoints and meets with each of the internal qualified reserves evaluator and independent reserves consultants independent of management to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

The Reserves Committee has reviewed Nexen's procedures for preparing the reserve estimates and related disclosures. It has reviewed the information with management, and met with the internal qualified reserves evaluator and the independent qualified reserves consultants. As a result of this, the Reserves Committee is satisfied that the internally-estimated reserves are reliable and free of material misstatement. Based on the recommendation of the Reserves Committee, the Board has approved the reserves estimates and related disclosures in the Form 10-K.

Reserves estimates are critical to many of our accounting estimates, including:

- Determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2004, $125 million of our total $175 million spent on exploration drilling was expensed in the year. If none of our drilling had been successful, our net income would have decreased by $33 million after tax.
- Calculating our unit-of-production depletion rates. Both proved and proved developed reserve[1] estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired and proved developed reserves are used where a property is drilled and developed. In 2004, oil and gas depletion of $541 million was recorded in depletion, depreciation, amortization and impairment expense. If our reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately $38 million, after tax, assuming no other changes to our reserves profiles.
- Assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a very significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of the MD&A.

Oil and Gas Accounting—Evaluation of Exploration Drilling

We use the successful efforts method to account for our oil and gas exploration and production activities. Under this method, exploration costs are capitalized pending an evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. Accounting rules require that this evaluation be made within at least one year of well completion. If our evaluation determines that the well did not encounter sufficient quantities of reserves to justify commercial production, the well costs are expensed as a dry hole and are reported in exploration expense. Exploratory wells that are judged to have discovered potentially sufficient quantities of oil and gas in areas where major capital expenditures are required before the commencement of production and where commercial viability requires the drilling of additional exploratory wells, remain capitalized as long as the drilling of additional exploratory wells is under way or firmly planned for the near future. For offshore deep-water exploratory discoveries, it is not unusual to have exploratory wells capitalized on our balance sheet for a number of years while we perform additional appraisal drilling and seismic work on the potential oil and gas field. We continually monitor the results of the additional appraisal work and expense capitalized well costs as dry holes if we determine that the potential field does not warrant further exploratory efforts in the near term.

We currently have an interest in an exploration block, offshore Nigeria where capitalized exploratory costs have been on our balance sheet for longer than one year. Major capital expenditures are required before production can begin and additional drilling efforts are underway to fully appraise the block. We are preparing a field development plan for the block with our partners for submission to the Nigerian government for approval. Once we obtain this approval and the project has been sanctioned, we will book proved reserves. Capitalized costs relating to this exploration block as at December 31, 2004 were $77 million (2003—$68 million). In the event that we are unable to book proved reserves for this project, amounts capitalized will be written off.

For more information with respect to amounts and geographic locations of costs incurred on exploration activity and amounts on our balance sheet relating to unproved properties, please refer to our Capitalized Costs and Costs Incurred tables set out in our supplemental Oil and Gas Producing Activities disclosures.

1 "Proved" oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered "proved" if economic producibility is supported by either actual production or a conclusive formation test. "Proved developed" oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operation methods.

Oil and Gas Accounting—Impairment

We evaluate our oil and gas properties for impairment if an adverse event or change occurs. Among other things, this might include falling oil and gas prices, a significant revision to our reserve estimates, changes in operating costs, or significant or adverse political changes. If one of these occurs, we estimate undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flows for a property are less than the carrying amount of that property, we calculate its fair value using a discounted cash flow approach. The property is then written down to its fair value.

We assessed our oil and gas properties for impairment at the end of 2004 and found no impairments were required based on our assumptions.

Our cash flow estimates for purposes of our impairment assessments require assumptions about two primary elements—future prices and reserves.

Our estimates of future prices require significant judgements about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US$17/bbl to US$56/bbl and US$2/mmbtu to US$19/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. Our estimates of future cash flows generally assume our long-term price forecast and forecast operating and development costs. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in this estimate would impact all except our chemicals business.

If forecast WTI crude oil prices were to fall to mid-US$20 levels our initial assessment of impairment indicators would not change. Although oil and gas prices fluctuate a great deal in the short-term, they are typically stable over a longer-time horizon. This mitigates the potential for impairment.

Any impairment charges would lower our net income.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test, is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment.

Business Combination—Purchase Price Allocation

During the fourth quarter of 2004, we acquired EnCana (UK) Limited, a company operating and exploring oil and gas properties located in the North Sea. We accounted for this acquisition using the purchase method of accounting. Under this method, we are required to record on our consolidated balance sheet the estimated fair values of the acquired company's assets and liabilities at the acquisition date. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill.

We have made various assumptions in determining the fair values of the acquired company's assets and liabilities. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimated (a) oil and gas reserves in accordance with our reserve standards, and (b) future prices of oil and gas.

Our reserve estimates were based on the work performed by our engineers and outside consultants. The judgments associated with these estimated reserves are described earlier in our critical accounting estimates discussion entitled "Oil and Gas Accounting—Reserves Determination". Our estimates of future prices were based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. The judgments associated with these estimates are described earlier in our critical accounting estimates discussion entitled "Oil and Gas Accounting—Impairment".

We applied our estimated future prices to the estimated reserves quantities acquired, and we estimated future operating and development costs, to arrive at estimated future net revenues for the properties acquired. For proved properties, we discounted the future net revenues using after-tax discount rates. The same principles were applied in arriving at the fair value of unproved properties acquired. These unproved properties generally represent the value of the probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, an appropriate risk-weighting factor was applied to the discounted future net revenues of the probable and possible reserves in each particular instance.

If the fair value allocated to oil and gas properties acquired had been decreased by $50 million, future income tax liabilities would have decreased by $20 million and goodwill would have increased by $30 million.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. Estimating our future asset retirement obligations requires us to make estimates and judgments with respect to activities that will occur many years into the future. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries in which we operate.

We record asset retirement obligations in our consolidated financial statements by discounting the present value of the estimated retirement obligations associated with our oil and gas wells and facilities and chemical plants. In arriving at amounts recorded, numerous assumptions and judgments are made with respect to ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligations we have recorded result in an increase to the carrying cost of our property, plant and equipment. The obligations are accreted with the passage of time. A change in any one of our assumptions could impact our asset retirement obligations, our property, plant and equipment and our net income.

It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results. We are confident, however, that our assumptions are reasonable.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In an effort to harmonize Canadian GAAP with US GAAP, the Canadian Accounting Standards Board has issued sections:

- 1530, *Comprehensive Income;*
- 3855, *Financial Instruments—Recognition and Measurement; and*
- 3865, *Hedges.*

Under these new standards, all financial assets should be measured at fair value with the exception of loans, receivables and investments that are intended to be held to maturity and certain equity investments, which should be measured at cost. Similarly, all financial liabilities should be measured at fair value when they are held for trading or they are derivatives.

Gains and losses on financial instruments measured at fair value will be recognized in the income statement in the periods they arise with the exception of gains and losses arising from:

- financial assets held for sale, for which unrealized gains and losses are deferred in other comprehensive income until sold or impaired; and
- certain financial instruments that qualify for hedge accounting.

Sections 3855 and 3865 make use of "other comprehensive income". Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income, but are excluded from net income. Unrealized gains and losses on qualifying hedging instruments, translation of self-sustaining foreign operations, and unrealized gains or losses on financial instruments held for sale will be included in other comprehensive income and reclassified to net income when realized. Comprehensive income and its components will be a required disclosure under the new standard.

These new standards are effective for fiscal years beginning on or after October 1, 2006 and early adoption is permitted. Adoption of these standards as at December 31, 2004 would have the following impact on our Consolidated Financial Statements:

(Cdn$ millions)	Increase
Accounts Receivable	6
Future Income Tax Liabilities	2
Shareholders' Equity	4

US Pronouncements

In November 2004, the Financial Accounting Standards Board (FASB) issued Statement 151, *Inventory Costs*. This statement amends ARB 43 to clarify that:

- abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage) should be recognized as current-period charges; and
- requires the allocation of fixed production overhead to inventory based on the normal capacity of the production facilities.

The provisions of this statement are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. We do not expect the adoption of this statement will have any material impact on our results of operations or financial position.

In December 2004, the FASB issued Statement 123(R), *Share-Based Payments*. This statement revises Statement 123, *Accounting for Stock-Based Compensation*, and supersedes APB Opinion 25, *Accounting for Stock Issued to Employees*.

Statement 123(R) requires all stock-based awards issued to employees to be measured at fair value and to be expensed in the income statement. This statement is effective for reporting periods beginning after June 15, 2005.

We are currently expensing stock-based awards issued to employees using the fair value method for equity based awards and the intrinsic method for liability based awards. Adoption of this standard will change our expense under US GAAP for tandem options and stock appreciation rights as these awards will be measured using the fair value method rather than the intrinsic method. We are currently evaluating the provisions of Statement 123(R) and have not yet determined the full impact this statement will have on our results of operations or financial position under US GAAP.

In December 2004, the FASB issued Statement 152, *Accounting for Real Estate*. This statement amends Statement 66, *Accounting for Sales of Real Estate*, to reference the financial accounting and reporting guidance for real estate time-sharing transactions that is provided in AICPA Statement of Position 04-2, *Accounting for Real Estate Time-Sharing Transactions*. This statement also amends FASB Statement 67, *Accounting for Costs and Initial Rental Operations of Real Estate Projects*, to state that the guidance for incidental operations and costs incurred to sell real estate projects does not apply to real estate time-sharing transactions. This statement is effective for financial statements with fiscal years beginning after June 15, 2005 and will not impact our results of operations or financial position.

In December 2004, the FASB issued Statement 153, *Exchanges of Nonmonetary Assets*, an amendment of APB Opinion 29, *Accounting for Nonmonetary Transactions*. This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. Under Statement 153, if a nonmonetary exchange of similar productive assets meets a commercial-substance test and fair value is determinable, the transaction must be accounted for at fair value resulting in the recognition of any gain or loss. This statement is effective for nonmonetary transactions in fiscal periods that begin after June 15, 2005. We do not expect the adoption of this statement will have any material impact on our results of operations or financial position.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to normal market risks inherent in the oil and gas and chemicals business, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

NON-TRADING

Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals.

To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices and North American supply and demand, and to a lesser extent local market conditions.

In 2004, WTI averaged US$41.40/bbl reaching a high of US$56.42/bbl and a low of US$32.41/bbl. NYMEX natural gas prices averaged US$6.19/mcf in 2004, reaching a high of US$8.12/mcf and a low of US$4.34/mcf.

Our sensitivities to commodity prices and the expected impact on our 2005 cash flow from operating activities and net income are as follows:

(Cdn$ millions)	Cash Flow	Net Income
WTI–US$1 change above US$43.17	50	35
WTI–US$1 change below US$43.17	25	17
NYMEX natural gas–US$0.10 change	10	7

These sensitivities to changes in benchmark prices for crude oil and natural gas are based on our estimated 2005 production levels for crude oil and natural gas and assume a Canadian/US dollar exchange rate of 80¢. Our estimated crude oil and natural gas production range for 2005 is between 230,000 and 250,000 boe/d, of which natural gas represents approximately 20%.

The majority of our oil and gas production is sold under short-term contracts, exposing us to short-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. From time to time, we actively manage these risks by using commodity futures, forwards, swaps and options.

In 2004, we purchased WTI put options to manage the commodity price risk exposure on a portion of our oil production in 2005 and 2006. These options establish an annual average WTI floor price of US$43/bbl in 2005 and US$38/bbl in 2006, as follows:

	Notional Volumes	Term	Average Price WTI (US$/bbl)
Crude Oil WTI Put Options	60,000 bbls/d	2005	43
	60,000 bbls/d	2006	38

In 2003, we entered into WTI and NYMEX gas forward contracts for a 12-month period. These forward contracts fixed our oil and gas prices at contract prices for the hedged volumes, less applicable price differentials, as follows:

	Hedged Volumes	Term	Average Price (US$)
Fixed WTI Price	5,000 bbls/d	April 2003 – March 2004	28.50/bbl
Fixed NYMEX Price	12,000 mmbtu/d	April 2003 – March 2004	5.35/mmbtu

Since actual prices during the contract period were higher than the fixed prices we received, our return was lower than what it would have been without these contracts in place. These contracts expired in March 2004.

Foreign Currency Risk

A substantial portion of our operations are denominated in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas and chemicals operations; and
- short-term and long-term borrowings.

The Canadian/US dollar exchange rate averaged 77¢ in 2004 with a high of 85¢ and a low of 72¢.

Our sensitivities to the US dollar and the expected impact of a one cent change on our 2005 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

(Cdn$ millions)	Cash Flow	Net Income	Capital Expenditures	Long-Term Debt
$0.01 change in US to Canadian dollar	25	13	18	50

Our sensitivities to changes in the Canadian/US dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar denominated long-term debt for 2005. These estimates are based on a WTI price for crude oil of US$40.00/bbl, a NYMEX natural gas price of US$6.50/mcf and a Canadian/US dollar exchange rate of 80¢.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. Since the timing of cash inflows and outflows is not necessarily interrelated, particularly for capital expenditures, we maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate our US-dollar borrowings as a hedge against our US-dollar net investment in foreign operations.

Our Buzzard project in the North Sea creates foreign currency exposure as a portion of the capital costs are denominated in British pounds (GBP) and Euros. In order to reduce our exposure to fluctuations in these currencies relative to the US dollar, we purchased foreign currency call options in early-2005. These options set a ceiling on most of our British pound and Euro spending exposure from February 2005 through to the end of 2006.

These call options effectively set a maximum GBP-US$ exchange rate of 1.95 on a total of GBP 84 million for the period March 2005 through June 2005, and a maximum rate of 2.00 on a total of GBP 185 million for the period July 2005 through December 2006. With respect to our Euro exposure, the call options effectively set a maximum Euro-US$ exchange rate of 1.40 on a total of Euros 59 million for the period February through September 2005. Managing our exchange rate exposure through the use of call options caps our exposure if the US dollar weakens relative to the British pound and the Euro but allows us to benefit fully from any strengthening of the US dollar relative to these currencies.

We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. At December 31, 2004, we held a foreign currency derivative instrument that obligates us and the counterparty to exchange principal and interest amounts. In November 2006, we will pay US$37 million and receive Cdn $50 million.

Interest Risk

We are exposed to fluctuations in short-term interest rates from our floating-rate debt and, to a lesser extent, our derivative instruments and long-term debt, as their market value is sensitive to interest rate fluctuations. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments.

Short-term interest rates for US dollar borrowings averaged 3.1% in 2004, reaching a high of 3.2% and low of 3.0%.

Our sensitivity to interest rates and the expected impact of a 1% change in interest rates on our 2005 cash flow from operating activities and net income is as follows:

(Cdn$ millions)	Cash Flow	Net Income
Interest Rates—1% change in rates	12	8

Our sensitivity to changes in interest rates is based on 2005 estimated average floating rate debt of $1.2 billion and a Canadian/US dollar exchange rate of 80¢.

Our floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2004 fixed-rate borrowings comprised 56% (2003—100%) of our long-term debt at an effective average rate of 6.6% (2003—8.2%). During the year we periodically drew on our unsecured syndicated term credit facilities and at December 31, 2004, floating rate debt comprised 44% (2003—nil) of our long-term debt at an effective average rate of 3.2% (2003—2.0%).

We had no interest rate swaps outstanding in 2004 or 2003.

TRADING

Commodity Price Risk

Our marketing operation is involved in the marketing and trading of crude oil, natural gas and power, through the use of both physical and financial contracts (energy trading activities). These activities expose us to commodity price risk. Open positions exist where not all contracted purchases and sales have been matched. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk). We control the level of market risk through daily monitoring of our energy-trading portfolio relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- stop loss limits; and
- stress testing.

VaR is a statistical estimate that is reliable when normal market conditions prevail. Our VaR calculation estimates the maximum probable loss given a 95% confidence level that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR using the Variance-Covariance method based on historical commodity price volatility and correlation inputs. Our estimate is based upon the following key assumptions:

- changes in commodity prices are normally distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

If a severe market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. There were no changes in the methodology we used to estimate VaR in 2004.

Stress testing complements our VaR estimate. It is used to ensure that we are not exposed to large losses, not captured by VaR, which might result from infrequent but extreme market conditions.

Our year-end, annual high, annual low and annual average VaR amounts are as follows:

(Cdn$ millions)	2004	2003	2002
Value at Risk			
Year-End	21	21	19
High	42	31	28
Low	17	14	12
Average	29	20	17

Our Board of Directors has approved formal risk management policies for our energy trading activities. Market and credit risks are monitored daily by a risk group that operates independently and ensures compliance with our risk management policies. The Finance Committee of the Board of Directors and our Risk Management Committee monitor our exposure to the above risks and review the results of our energy trading activities regularly.

CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our receivables are with counterparties in the oil and gas and energy trading industry and are subject to normal industry credit risk. We take the following measures to reduce this risk:

- we assess the financial strength of our counterparties through a rigorous credit process;
- we limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- we routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the Board;
- we set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- we review counterparty credit limits regularly; and
- we use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. At December 31, 2004:

- over 90% of our receivables were investment grade;
- only two counterparties individually made up more than 5% of our credit exposure. All were investment grade.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Items 1 and 2—Business and Properties* and *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations*, are forward-looking statements[1]. Forward-looking statements are generally identifiable by terms such as *anticipate, believe, intend, plan, expect, estimate, budget, outlook* or other similar words, and include statements relating to future production associated with our Long Lake, North Sea and West Africa projects.

These statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. These risks, uncertainties and other factors include:

- market prices for oil, natural gas and chemicals products;
- our ability to produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions that increase taxes, change environmental and other laws and regulations;
- renegotiations of contracts; and
- political uncertainty, including actions by terrorists, insurgent or other groups or armed other conflict, including conflict between states.

The above items and their possible impact are discussed more fully in the section, titled *Business Risk Management* in Item 7 and *Quantitative and Qualitative Disclosures about Market Risk in Item 7A*.

The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and management's future course of action depends upon our assessment of all information available at that time. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues from our operations in Yemen;
- future capital expenditures and their allocation to exploration and development activities;
- future asset dispositions;
- future sources of funding for our capital program;
- future debt levels;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- future expenditures and future allowances relating to environmental matters; and
- dates by which certain areas will be developed or will come on stream.

We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. We undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements.

1 Within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, as amended.

Special Note to Canadian Investors

Nexen is a US Securities and Exchange Commission (SEC) registrant and a Form 10-K and related forms filer. Therefore, our reserves estimates and securities regulatory disclosures generally follow SEC requirements.

In 2003, Canadian regulatory authorities adopted *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101) which prescribe that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. We have been granted the following exemptions permitting us to:

- substitute our SEC disclosures for much of the annual disclosure required by NI 51-101;
- prepare our reserves estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the US as promulgated by the Society of Petroleum Engineers, and the standards of the *Canadian Oil and Gas Evaluation Handbook* (COGE Handbook) modified to reflect SEC requirements;
- dispense with the requirement to have our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, evaluated or audited by independent qualified reserves evaluators; and
- not disclose certain prescribed information pertaining to prospects if such disclosures would result in the contravention of a legal obligation, would likely be detrimental to our competitive interests or the information does not exist.

As a result of these exemptions, Canadian investors should note the following fundamental differences in reserves estimates and related disclosures contained in the Form 10-K:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein* calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of proved and proved producing reserves by country only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not require separate disclosure of proved undeveloped reserves or related future development costs whereas NI 51-101 requires disclosure of more information regarding proved undeveloped reserves, related development plans and future development costs;
- the SEC does not require disclosure of finding and development (F&D) costs per boe of proved reserves additions whereas NI 51-101 requires that various F&D costs per boe be disclosed. NI 51-101 requires that F&D costs be calculated by dividing the aggregate of exploration and development costs incurred in the current year and the change in estimated future development costs relating to proved reserves by the additions to proved reserves in the current year. However, this will generally not reflect full cycle finding and development costs related to reserve additions for the year;
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's board of directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports;
- the SEC does not consider the upgrading component of our integrated oil sands project at Long Lake as an oil and gas activity, and therefore permits recognition of bitumen reserves only. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits recognition of synthetic reserves. Given low year-end bitumen prices, we have not recognized any proved bitumen reserves under SEC requirements whereas under NI 51-101 we would have recognized 205 million barrels of proved synthetic reserves (before royalties); and
- the SEC considers our Syncrude operation as a mining activity rather than an oil and gas activity, and therefore does not permit related reserves to be included with oil and gas reserves. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits them to be included with oil and gas reserves. We have provided a separate table showing our share of the Syncrude proved reserves as well as the additional disclosures relating to mining activities required by SEC requirements.

The foregoing is a general description of the principal differences only.

NI 51-101 requires that we make the following disclosures:

- we use oil equivalents (boes) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

financial statements

Aspen, US Gulf of Mexico

contents

Item 8. Financial Statements and Supplementary Financial Information

REPORT OF MANAGEMENT

February 7, 2005

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and fair presentation of the consolidated financial statements, as well as the financial reporting process that gives rise to such consolidated financial statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our consolidated financial statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for the development and implementation of internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company, and that our records are reliable for preparing our consolidated financial statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees including the chief executive officer, chief financial officer and chief accounting officer or controller.

Our Board of Directors is responsible for reviewing and approving the consolidated financial statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee) with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves and the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors, and includes four directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors, and the independent auditors, to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent auditors and also considers their independence, reviews their fees and (subject to applicable securities laws), pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent registered Chartered Accountants have full and unlimited access to the Audit Committee, with or without the presence of management.

(signed) "Charles W. Fischer"
President and Chief Executive Officer

(signed) "Marvin F. Romanow"
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited the consolidated balance sheet of Nexen Inc. as at December 31, 2004 and 2003 and the consolidated statements of income, cash flows and shareholders' equity for each of the years in the three year period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as at December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 7, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Calgary, Canada
February 7, 2005

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

COMMENTS BY AUDITORS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 1(r) to the consolidated financial statements. Our report to the board of directors and shareholders on the consolidated financial statements of Nexen Inc., dated February 7, 2005, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Calgary, Canada
February 7, 2005

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

Nexen Inc.
Consolidated Statement of Income
For the Three Years Ended December 31, 2004

Cdn$ millions, except per share amounts	2004	2003	2002
		Restated for Changes in Accounting Principles Note 1(r)	Restated for Changes in Accounting Principles Note 1(r)
Revenues			
Net Sales	3,176	2,844	2,341
Marketing and Other (Note 14)	729	610	496
	3,905	3,454	2,837
Expenses			
Operating	762	721	701
Depreciation, Depletion, Amortization and Impairment (Note 5)	744	995	632
Transportation and Other	564	489	475
General and Administrative	299	190	151
Exploration	246	199	178
Interest (Note 7)	143	169	181
	2,758	2,763	2,318
Income from Continuing Operations before Income Taxes	1,147	691	519
Provision for Income Taxes (Note 15)			
Current	248	214	207
Future	119	(73)	(44)
	367	141	163
Net Income from Continuing Operations	780	550	356
Net Income from Discontinued Operations (Note 11)	13	28	53
Net Income	**793**	**578**	**409**
Earnings Per Common Share from Continuing Operations ($/share)			
Basic (Note 10)	6.07	4.45	2.91
Diluted (Note 10)	5.99	4.41	2.87
Earnings Per Common Share ($/share)			
Basic (Note 10)	6.17	4.67	3.34
Diluted (Note 10)	6.09	4.63	3.30

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Consolidated Balance Sheet
December 31, 2004 and 2003

Cdn$ millions, except share amounts	2004	2003
		Restated for Changes in Accounting Principles Note 1(r)
ASSETS		
Current Assets		
Cash and Cash Equivalents	74	1,087
Accounts Receivable (Note 3)	2,136	1,423
Inventories and Supplies (Note 4)	351	270
Other	42	79
Total Current Assets	2,603	2,859
Property, Plant and Equipment (Note 5)	8,643	4,550
Goodwill	375	36
Future Income Tax Assets (Note 15)	333	108
Deferred Charges and Other Assets (Note 17)	429	164
TOTAL ASSETS	**12,383**	**7,717**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-Term Borrowings (Note 7)	100	-
Current Portion of Long-Term Debt (Note 7)	-	572
Accounts Payable and Accrued Liabilities	2,416	1,404
Accrued Interest Payable	34	44
Dividends Payable	13	12
Total Current Liabilities	2,563	2,032
Long-Term Debt (Note 7)	4,259	2,517
Future Income Tax Liabilities (Note 15)	2,131	720
Asset Retirement Obligations (Note 8)	421	305
Deferred Credits and Other Liabilities	142	68
Shareholders' Equity (Note 9)		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2004–129,199,583 shares		
2003–125,606,107 shares	637	513
Contributed Surplus	-	1
Retained Earnings	2,335	1,594
Cumulative Foreign Currency Translation Adjustment	(105)	(33)
Total Shareholders' Equity	2,867	2,075
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**12,383**	**7,717**

Commitments, Contingencies and Guarantees (Note 12 and 15)

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(Signed) "Charles W. Fischer"
Director

(Signed) "David A. Hentschel"
Director

Nexen Inc.
Consolidated Statement of Cash Flows
For the Three Years Ended December 31, 2004

Cdn$ millions	2004	2003	2002
		Restated for Changes in Accounting Principles Note 1(r)	Restated for Changes in Accounting Principles Note 1(r)
Operating Activities			
Net Income from Continuing Operations	780	550	356
Net Income from Discontinued Operations	13	28	53
Charges and Credits to Income not Involving Cash (Note 16)	903	1,018	724
Exploration Expense	246	199	178
Changes in Non-Cash Working Capital (Note 16)	(122)	(320)	(46)
Other (Note 16)	(213)	(70)	(15)
	1,607	1,405	1,250
Financing Activities			
Proceeds from Long-Term Notes and Debentures (Note 7)	1,779	651	790
Repayment of Long-Term Notes and Debentures (Note 7)	(300)	-	-
Proceeds from (Repayment of) Term Credit Facilities, Net	83	93	(419)
Proceeds from (Repayment of) Short-Term Borrowings, Net	101	(18)	(33)
Proceeds from Subordinated Debentures (Note 7)	-	613	-
Redemption of Preferred Securities (Note 7)	(289)	(340)	-
Dividends on Common Shares	(52)	(40)	(37)
Issue of Common Shares	124	73	51
Other	(20)	(26)	(23)
	1,426	1,006	329
Investing Activities			
Business Acquisition, Net of Cash Acquired (Note 2)	(2,583)	-	-
Capital Expenditures			
Exploration and Development	(1,582)	(1,276)	(1,477)
Proved Property Acquisitions	(4)	(164)	(4)
Chemicals, Corporate and Other	(95)	(54)	(144)
Proceeds on Disposition of Assets	34	293	49
Changes in Non-Cash Working Capital (Note 16)	244	(18)	7
Other	(27)	-	-
	(4,013)	(1,219)	(1,569)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(33)	(164)	(12)
Increase (Decrease) in Cash and Cash Equivalents	(1,013)	1,028	(2)
Cash and Cash Equivalents—Beginning of Year	1,087	59	61
Cash and Cash Equivalents—End of Year	74	1,087	59

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Consolidated Statement of Shareholders' Equity
For the Three Years Ended December 31, 2004

Cdn$ millions	2004	2003	2002
		Restated for Changes in Accounting Principles Note 1(r)	Restated for Changes in Accounting Principles Note 1(r)
Common Shares (Note 9)			
Balance at Beginning of Year	513	440	389
Exercise of Stock Options	93	50	27
Issue of Common Shares	31	23	24
Balance at End of Year	**637**	**513**	**440**
Contributed Surplus			
Balance at Beginning of Year	1	-	-
Stock Based Compensation Expense (Note 9)	2	1	-
Modification of Stock Option Plan to Tandem Option Plan (Note 9)	(3)	-	-
Balance at End of Year	**-**	**1**	**-**
Retained Earnings			
Balance at Beginning of Year	1,594	1,056	697
Retroactive Adjustment for Changes in Accounting Principles (Note 1)	-	-	(13)
Net Income	793	578	409
Dividends on Common Shares	(52)	(40)	(37)
Balance at End of Year	**2,335**	**1,594**	**1,056**
Cumulative Foreign Currency Translation Adjustment			
Balance at Beginning of Year	(33)	94	94
Retroactive Adjustment for Changes in Accounting Principles (Note 1)	-	-	(34)
Translation Adjustment, Net of Income Taxes	(72)	(127)	34
Balance at End of Year	**(105)**	**(33)**	**94**

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Notes to Consolidated Financial Statements

Cdn$ millions except as noted

1. Accounting Policies

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and US GAAP on the Consolidated Financial Statements is disclosed in Note 19. We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates, including those related to litigation, environmental and dismantlement liabilities, income taxes and determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

(A) PRINCIPLES OF CONSOLIDATION

The Consolidated Financial Statements include the accounts of Nexen Inc. and our subsidiary companies (Nexen, we or our). All subsidiary companies are wholly owned and all material intercompany accounts and transactions have been eliminated. We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. We also proportionately consolidate our 7.23% undivided interest in the Syncrude joint venture, which is considered a mining activity under US regulations. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities, the significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(B) ACCOUNTS RECEIVABLE

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(i)). Our allowance for doubtful accounts provides for specific doubtful receivables.

(C) INVENTORIES AND SUPPLIES

Inventories and supplies for our oil and gas, marketing and chemicals operations are stated at the lower of cost and net realizable value. Cost is determined on the first-in, first-out method or average basis.

Inventory costs include expenditures and other costs, including depreciation, depletion and amortization, directly or indirectly incurred in bringing the inventory to its existing condition.

(D) PROPERTY, PLANT AND EQUIPMENT (PP&E)

Property, plant and equipment is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E.

We follow successful efforts accounting for our oil and gas business. All property acquisition costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the acquisition costs are reclassified to proved property acquisition costs. Exploration drilling costs are capitalized pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability within twelve months of drilling completion. Exploration wells that discover potentially commercial quantities of reserves in areas requiring major capital expenditures before the commencement of production and where commercial viability requires the drilling of additional exploratory wells, remain capitalized as long as the drilling of additional exploratory wells is under way or firmly planned. All other exploration costs, including geological and geophysical and annual lease rentals are expensed to earnings as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

Property, plant and equipment for our Syncrude operation is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established and we intend to proceed with development. We defer these costs in PP&E until the commencement of commercial operations or production. Otherwise, development costs are expensed as incurred. Development costs include pre-operating revenues and costs.

(E) DEPRECIATION, DEPLETION, AMORTIZATION AND IMPAIRMENT (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs over remaining proved reserves. Depletion is considered a cost of inventory when the oil and gas is produced. When this inventory is sold, the depletion is charged to DD&A expense.

Our Syncrude PP&E is depleted using the unit-of-production method. Capitalized costs are depleted over proved and probable reserves within developed areas of interest.

We depreciate other plant and equipment costs, including our chemicals facilities, using the straight-line method based on the estimated useful lives of the assets, which range from 3 years to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur that indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. These events or conditions occur periodically. If carrying value exceeds the sum of undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated total future cash flows, discounted for the time value of money, and we expense the excess carrying value to depreciation, depletion, amortization and impairment. Our cash flow estimates require assumptions about future commodity prices, operating costs and other factors. Actual results can differ from those estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for those properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(F) CARRIED INTEREST

We conduct certain international operations jointly with foreign governments in accordance with production sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs are recorded in operating expense when incurred and capital costs are recorded in PP&E and are expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(G) ASSET RETIREMENT OBLIGATIONS

We provide for future asset retirement obligations on our resource properties, facilities, production platforms, pipelines and chemicals facilities based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to property, plant and equipment as an asset retirement cost. The asset retirement obligation accretes until the time the retirement obligation is expected to settle while the asset retirement cost is amortized over the useful life of the underlying property, plant and equipment.

The amortization of the asset retirement cost and the accretion of the asset retirement obligation are included in depreciation, depletion, amortization and impairment. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the period of settlement.

(H) GOODWILL

Goodwill is recorded at cost and is not amortized. We test goodwill for impairment annually based on estimated future cash flows of the reporting unit to which the goodwill is attributable. In addition, we test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount. Our goodwill is attributable to our Marketing and United Kingdom reporting units.

(I) REVENUE RECOGNITION

Crude Oil and Natural Gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada, the United States and the United Kingdom, our customers typically take title when the crude oil and natural gas reaches the end of the pipeline. For our other international operations, our customers take title when the crude oil is loaded onto the tanker. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities, and underlifts as assets. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty payments to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty payments. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations. See Note 1(f).

Chemicals

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery only takes place when we have a sales contract in place specifying delivery volumes and sales prices. We assess customer credit worthiness before entering into sales contracts to minimize collection risk.

Marketing

Substantially all of the physical purchase and sales contracts entered into by our marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively derivative instruments) held by our marketing operation are stated at fair value on the balance sheet date unless the requirements for hedge accounting are met (see Note 1(m)). We record any change in fair value as a gain or loss in marketing and other.

Any margin realized by our marketing department on the sale of our proprietary oil and gas production is included in marketing and other. We assess customer credit worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have the legal right of offset. Our marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments have been recorded as deferred liabilities and are recognized in net income as the transportation is used.

(J) INCOME TAXES

We follow the liability method of accounting for income taxes (see Note 15). This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, since we intend to invest such earnings indefinitely in foreign operations.

(K) FOREIGN CURRENCY TRANSLATION

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars as follows:

- assets and liabilities using exchange rates at the balance sheet dates; and
- revenues and expenses using the average exchange rates throughout the year.

Gains and losses resulting from this translation are included in the cumulative foreign currency translation adjustment in shareholders' equity.

Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from translation, except on our designated US-dollar debt, are included in income. We have designated US-dollar debt as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other in the Consolidated Statement of Income.

(L) CAPITALIZED INTEREST

We capitalize interest on major development projects until such time as the project is substantially complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest expense.

(M) DERIVATIVE INSTRUMENTS

Non-Trading Activities

We use derivative instruments such as physical purchase and sales, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Note 6). We record these instruments at fair value at the balance sheet date and record any change in fair value as a net gain or loss in marketing and other during the period of change unless the requirements for hedge accounting are met. Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. We recognize gains and losses on the derivative instruments designated as hedges in the same period as the gains or losses on the hedged items are recognized. If effective correlation ceases, hedge accounting is terminated and future changes in the market value of the derivative instrument are included as gains or losses in marketing and other in the period of change.

Trading Activities

Our marketing operation uses derivative instruments for marketing and trading crude oil and natural gas including:

- commodity contracts settled with physical delivery;
- exchange-traded futures and options; and
- non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other during the period of change. The fair value of these instruments is recorded as accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond 12 months we record them as deferred charges and other assets or deferred credits and other liabilities.

(N) EMPLOYEE BENEFITS

The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses which exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. We measure the plan assets and the accrued benefit obligation on October 31 each year.

(O) STOCK-BASED COMPENSATION

In 2003, we adopted the fair-value method of accounting for stock options granted to employees and directors. We recorded stock-based compensation expense in the Consolidated Statement of Income as general and administrative expenses for all options granted on or after January 1, 2003, with a corresponding increase to contributed surplus. Compensation expense for options granted was based on estimated fair values at the time of grant and we recognized the expense over the vesting period of the option.

In May 2004, we modified our stock option plan to a tandem option plan by including a cash feature. The tandem options give the holders a right to either purchase common shares at the exercise price or to receive cash payments equal to the excess of the market value of the common shares over the exercise price. As a result of the modification, we record obligations for the tandem options using the intrinsic-value method of accounting and recognize compensation expense. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the recorded liability amount is transferred to share capital.

Stock options awarded to our US employees on or after December 1, 2004 do not include a cash feature and are not accounted for as tandem options. Instead, we account for these options using the fair-value method. Compensation expense is based on estimated fair values at the time of grant and is recognized over the vesting period of the options. The expense is included as general and administrative expense with a corresponding increase to contributed surplus.

We provide stock appreciation rights to employees as described in Note 9. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

(P) CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term, highly liquid investments that mature within three months of their purchase. They are recorded at cost, which approximates market value.

(Q) TRANSPORTATION

We pay to transport the crude oil, natural gas and chemicals products that we market, and then bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as a cost to us and is recorded as transportation and other.

(R) CHANGES IN ACCOUNTING PRINCIPLES

Asset Retirement Obligations (ARO)

On January 1, 2004, we retroactively adopted the Canadian Institute of Chartered Accountants (CICA) standard S.3110, *Asset Retirement Obligations*. This new standard requires recognition of a liability for the future retirement obligations associated with our property, plant and equipment, which includes oil and gas wells and facilities, and chemicals plants. We previously provided for dismantlement and site restoration costs on our oil and gas wells and facilities, and chemicals plants based on estimates established by current legislation and industry practices. We recorded a provision for these costs in DD&A based on proved reserves or estimated remaining asset lives. The change was adopted retroactively and all prior periods presented have been restated.

Financial Instruments

In the fourth quarter of 2004, we retroactively adopted the changes to CICA standard S.3860, *Financial Instruments*. These changes require that fixed-amount contractual obligations that can be settled by issuing a variable number of equity instruments be classified as a liability. Our US-dollar denominated preferred and subordinated securities have these characteristics and accordingly have been reclassified as long-term debt. Dividends and interest on these securities have been included in interest expense and issue costs previously charged to retained earnings have been amortized over the life of the securities. Unamortized issue costs have been expensed on the redemption of the preferred securities in 2003 and 2004. Foreign exchange gains or losses from translation of the US-dollar amounts have been included as cumulative foreign currency translation adjustments. The change was adopted retroactively and all prior periods presented have been restated.

Generally Accepted Accounting Principles

In 2004, we adopted CICA standard S.1100, *Generally Accepted Accounting Principles* which eliminated general practice in Canada as a component of GAAP. Our accounting policy for 2004 is to include geological and geophysical costs as operating cash outflows in our Consolidated Statement of Cash Flows. For previous years, we included geological and geophysical costs as investing cash outflows consistent with industry practice in Canada. In our Consolidated Statement of Cash Flows for 2004, we included $73 million of geological and geophysical costs as other operating cash outflows. For 2003 and 2002, geological and geophysical costs of $62 million and $80 million, respectively, are included in investing activities as exploration and development capital expenditures. This change in accounting policy was adopted prospectively.

Impact of Changes in Accounting Principles

The impact of the changes on our 2004 Consolidated Statement of Income resulted in additional interest expense of $3 million for dividends on preferred securities, additional transportation and other expense of $11 million for the unamortized issue costs on the redemption of preferred securities, and a corresponding reduction in the provision for income taxes of $6 million. The impact of these changes in accounting principles on our Consolidated Statement of Income and Earnings per Common Share for the years ended December 31, 2003 and 2002 and on our Consolidated Balance Sheet at December 31, 2003, are shown below.

Consolidated statement of income for the years ended December 31, 2003 and 2002

	2003	2002
Depletion, Depreciation, Amortization and Impairment Expense as Reported[1]	995	632
Less: Dismantlement and Site Restoration	(33)	(35)
Plus: Asset Retirement Cost Amortization	14	15
Plus: Asset Retirement Obligation Accretion	19	20
Depletion, Depreciation, Amortization and Impairment Expense as Restated	**995**	**632**
Transportation and Other Expense as Reported	461	475
Plus: Unamortized Issue Costs on Redemption of Preferred Securities	28	-
Transportation and Other Expense as Restated	**489**	**475**
Interest Expense as Reported	105	109
Plus: Dividends on Preferred Securities	64	72
Interest Expense as Restated	**169**	**181**
Provision for Future Income Taxes as Reported[1]	(42)	(15)
Plus: Tax Effect of Changes in Accounting Principles	(31)	(29)
Provision for Future Income Taxes as Restated	**(73)**	**(44)**

Note:
1 Adjusted for discontinued operations.

Net income and earnings per common share for the years ended December 31, 2003 and 2002

	2003	2002
Net Income Attributable to Common Shareholders		
As Reported	599	409
Less: Unamortized Issue Costs on Preferred Securities Redemption, Net of Income Taxes	(21)	-
As Restated	**578**	**409**
Earnings per Common Share ($/share)		
Basic as Reported	4.84	3.34
Restated	4.67	3.34
Diluted as Reported	4.79	3.30
Restated	4.63	3.30

Consolidated balance sheet as at December 31, 2003

	As Reported	ARO Change	Financial Instruments Change	As Restated
Property, Plant and Equipment	4,469	81	-	4,550
Deferred Charges and Other Assets	153	-	11	164
Current Portion of Long-Term Debt	291	-	281	572
Long-Term Debt	2,485	-	32	2,517
Future Income Tax Liabilities	724	(17)	13	720
Asset Retirement Obligations	-	305	-	305
Dismantlement and Site Restoration	179	(179)	-	-
Preferred and Subordinated Securities	364	-	(364)	-
Retained Earnings	1,659	(28)	(37)	1,594
Cumulative Foreign Currency Translation Adjustment	(119)	-	86	(33)

(S) RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2004.

2. Business Acquisition

On December 1, 2004, we acquired 100% of the issued and outstanding share capital of EnCana (UK) Limited (EnCana UK) from EnCana Corporation (EnCana) for cash consideration of US$2.1 billion, subject to certain adjustments. EnCana UK held all of EnCana's offshore oil and gas assets in the North Sea.

We acquired EnCana UK to establish a strategic presence in the North Sea by acquiring operatorship of the Buzzard field development and operatorship of the producing Scott and Telford fields. The acquisition also gives us access to interests in several satellite discoveries and over 700,000 net undeveloped exploration acres. In addition, we acquired the management and technical teams that found and are developing the Buzzard discovery. Goodwill paid is attributable to the established North Sea presence acquired and the knowledge and business relationships acquired through the management team and employees of EnCana UK.

The acquisition has been accounted for using the purchase method and the results of EnCana UK have been consolidated with the results of Nexen from December 1, 2004. The following table shows the allocation of the purchase price based on the estimated fair value of the assets and liabilities acquired:

Purchase Price, Net of Cash Acquired:	
Cash Paid	2,561
Transaction Costs	22
	2,583

Purchase Price Allocated as follows:	
Accounts Receivable	310
Inventories and Supplies	11
Other Current Assets	2
Property, Plant and Equipment	3,395
Future Income Tax Assets	239
Goodwill[1]	334
Deferred Charges and Other Assets	12
Accounts Payable and Accrued Liabilities	(289)
Asset Retirement Obligations	(134)
Future Income Tax Liabilities	(1,284)
Deferred Credits and Other Liabilities	(13)
Total Purchase Price Allocated	**2,583**

Note:
1 The amount of goodwill deductible for tax purposes is nil.

The unaudited pro forma results for the years ended December 31, 2004 and 2003 are shown below as if the acquisition had occurred on January 1, 2003. Pro forma results are not necessarily indicative of actual results or future performance.

	2004	2003
Revenues	4,258	3,642
Net Income	841	595
Earnings Per Common Share—Basic ($/share)	6.54	4.81
Earnings Per Common Share—Diluted ($/share)	6.46	4.75

3. Accounts Receivable

	2004	2003
Trade		
Marketing	1,452	1,078
Oil and Gas	593	263
Chemicals and Other	57	47
	2,102	1,388
Non-Trade	49	50
	2,151	1,438
Allowance for Doubtful Receivables	(15)	(15)
Total Accounts Receivable	**2,136**	**1,423**

4. Inventories And Supplies

	2004	2003
Finished Products		
Marketing	199	138
Oil and Gas	6	16
Chemicals and Other	13	12
	218	166
Work in Process	4	6
Field Supplies	129	98
Total Inventories and Supplies	**351**	**270**

5. Property, Plant And Equipment

	2004			2003		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Yemen	678	506	172	656	489	167
Yemen–Carried Interest	1,360	1,044	316	1,242	1,008	234
Canada	3,463	1,615	1,848	2,951	1,460	1,491
United States	2,249	1,037	1,212	2,153	887	1,266
United Kingdom	3,499	16	3,483	-	-	-
Other Countries	535	408	127	534	410	124
Marketing	157	64	93	158	57	101
	11,941	4,690	7,251	7,694	4,311	3,383
Syncrude	1,030	155	875	821	144	677
Chemicals	815	409	406	774	381	393
Corporate and Other	201	90	111	168	71	97
Total Property, Plant and Equipment	**13,987**	**5,344**	**8,643**	**9,457**	**4,907**	**4,550**

The above table includes capitalized costs of $3,945 million (2003—$630 million) relating to unproved properties and projects under construction or development. These costs are not being depreciated, depleted or amortized. We currently have an interest in an exploration block, offshore Nigeria, where capitalized exploratory costs have been on our balance sheet for longer than one year. Major capital expenditures are required before production can begin and additional drilling efforts are underway to fully appraise the block. Exploratory drilling costs were first capitalized in 1998 and we have subsequently drilled a further seven successful wells on the block. We are preparing a field development plan for the block with our partners for submission to the Nigerian government for approval. Once we obtain this approval and the project has been sanctioned, we will book proved reserves. Capitalized costs relating to this exploration block as at December 31, 2004 were $77 million (2003—$68 million).

Our 2003 depreciation, depletion, amortization and impairment expense in the Consolidated Statement of Income includes an impairment charge of $269 million relating to certain Canadian oil and gas properties. The impairment results from negative reserve revisions and is largely attributable to Canadian heavy oil properties. The revisions resulted from changes in late field-life economic assumptions, changes in proved undeveloped reserves based on drilling results and geological mapping, and reassessments of estimated future production profiles.

We incurred $35 million (2003—$20 million) related to research and development activities. Costs of $26 million (2003—$14 million) were recorded in other expense on the Consolidated Statement of Income. The remaining costs have been deferred and are included in PP&E.

	2004	2003
Development Costs Deferred, Beginning of Year	6	-
Deferred in the Year	9	6
Amortized in the Year	-	-
Development Costs Deferred, End of Year	**15**	**6**

6. Derivative Instruments And Financial Risk Management

(A) CARRYING VALUE AND ESTIMATED FAIR VALUE OF DERIVATIVE AND FINANCIAL INSTRUMENTS

The carrying value, fair value, and unrecognized gains or losses on our outstanding derivatives and long-term financial assets and liabilities at December 31 are:

	2004			2003		
(Cdn$ millions)	Carrying Value	Fair Value	Unrecognized Gain (Loss)	Carrying Value	Fair Value	Unrecognized Gain (Loss)
Commodity Price Risk						
Non-Trading Activities						
Future Sale of Oil and Gas Production	-	-	-	-	(3)	(3)
Crude Oil Put Options	200	200	-	-	-	-
Trading Activities						
Crude Oil and Natural Gas	83	83	-	101	101	-
Future Sale of Gas Inventory	-	6	6	-	(11)	(11)
Foreign Currency Risk						
Non-Trading Activities	7	7	-	-	(1)	(1)
Trading Activities	10	10	-	5	5	-
Total Derivatives	300	306	6	106	91	(15)
Financial Assets and Liabilities						
Long-Term Debt	(4,259)	(4,503)	(244)	(3,089)	(3,316)	(227)

The estimated fair value of all derivative instruments is based on quoted market prices and, if not available, on estimates from third-party brokers or dealers. The carrying value of cash and cash equivalents, amounts receivable and short-term obligations approximates their fair value because the instruments are near maturity.

(B) COMMODITY PRICE RISK MANAGEMENT

Non-Trading Activities

We generally sell our crude oil and natural gas under short-term market based contracts.

Future sale of oil and gas production

In 2003, we entered into WTI and NYMEX gas forward contracts for a 12-month period. These forward contracts fixed our oil and gas prices at the contract prices for the hedged volumes, less applicable price differentials. Since actual prices during the contract period were higher than the fixed prices we received, our return was lower than it would have been without these contracts in place. These contracts expired in March 2004.

Crude oil put options

We purchased WTI crude oil put options to manage the commodity price risk exposure of a portion of our oil production in 2005 and 2006. These options establish an annual average WTI floor price of US$43/bbl in 2005 and US$38 in 2006 at a cost of $144 million. The WTI crude oil put options are stated at fair value and included in deferred charges and other assets as they settle beyond 12 months of the balance sheet date. Any change in fair value is included in marketing and other on the Consolidated Statement of Income.

WTI Crude Oil Put Options	Notional Volumes (bbls/d)	Term	Average Price (WTI) (US$/bbl)	Market Value (Cdn$ millions)
	30,000	2005	44	57
	20,000	2005	43	33
	10,000	2005	41	12
	30,000	2006	39	53
	20,000	2006	38	32
	10,000	2006	36	13
				200

Trading Activities

Crude oil and natural gas

We enter into physical purchase and sales contracts as well as financial commodity contracts to enhance our price realizations and lock-in our margins. The physical and financial commodity contracts (derivative contracts) are stated at market value. The $83 million fair value of the contracts has been recognized in net income.

Future sale of gas inventory

We have certain NYMEX futures contracts and swaps in place, which effectively lock-in our margins on the future sale of our natural gas inventory in storage. We have designated, in writing, some of these derivative contracts as cash flow hedges of the future sale of our storage inventory. As a result, gains and losses on these designated futures contracts and swaps are recognized in net income when the inventory in storage is sold. The principal terms of these outstanding contracts and the unrecognized gains and losses at December 31, 2004 are:

	Hedged Volumes (mmcf)	Month	Average Price (US$/mcf)	Unrecognized Gain (Cdn$ millions)
NYMEX Natural Gas Futures	3,740	January 2005	6.825	2
	5,660	February 2005	6.53	2
NYMEX Natural Gas Fixed Price Swaps	1,000	January 2005	7.147	1
	500	February 2005	6.987	1
				6

(C) FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

Non-Trading Activities

We designate our US-dollar debt as a hedge against our net investment in self-sustaining foreign operations. The US-dollar debt issued in November 2003 to re-finance existing designated US-dollar debt was designated as part of the hedge in February 2004. In December 2004, we drew US$1.5 billion against term credit facilities established for our North Sea acquisition. This amount has been designated as a hedge of our investment in our self-sustaining foreign operations.

The foreign exchange gains or losses related to the designated debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. Undesignated foreign exchange gains or losses on the November 2003 debt issues were included in marketing and other prior to the designation of this debt as a hedging instrument in February 2004. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at December 31 are as follows:

(US$ millions)	2004	2003
Net Investment in Self-Sustaining Foreign Operations	3,973	1,574
US-Dollar Debt	3,315	1,143

We also have exposure to currencies other than the US dollar. A portion of our capital spending on our Long Lake Project is denominated in Euros and Japanese Yen. A portion of our United Kingdom operating expenses and capital spending is denominated in British Pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. At December 31, 2004, we held a foreign currency derivative instrument that obligates us and the counterparty to exchange principal and interest amounts. In November 2006, we will pay US$37 million and receive Cdn $50 million (see Note 7). We have recognized a gain of $7 million for the fair value of this derivative instrument.

Trading Activities

Our sales and purchases of crude oil and natural gas are generally transacted in or referenced to the US dollar, as are most of the financial commodity contracts used by our marketing group. We enter into forward contracts to sell US dollars. When combined with certain commodity sales contracts, either physical or financial, these forward contracts allow us to lock-in our margins on the future sale of crude oil and natural gas. The fair value of our US dollar forward contracts at December 31, 2004 was $10 million (2003—$5 million). This fair value has been recognized in net income and settles within one year.

(D) TOTAL CARRYING VALUE OF DERIVATIVE CONTRACTS RELATED TO TRADING ACTIVITIES

Amounts related to derivative instruments held by our marketing operation are equal to fair value as we use mark-to-market accounting, and are as follows at December 31:

(Cdn $millions)	2004	2003
Accounts Receivable	177	102
Deferred Charges and Other Assets[1]	91	63
Total Derivative Contract Assets	**268**	**165**
Accounts Payable and Accrued Liabilities	129	34
Deferred Credits and Other Liabilities[1]	46	25
Total Derivative Contract Liabilities	**175**	**59**
Total Derivative Contract Net Assets	**93**	**106**

Note:
1 These derivative instruments settle beyond 12 months and are considered non-current.

(E) INTEREST RATE RISK MANAGEMENT

We use fixed and floating rate debt to finance our operations. The floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2004, fixed-rate borrowings comprised 56% (2003—100%) of our long-term debt at an effective average rate of 6.6% (2003—8.2%). During the year we periodically drew on our floating rate unsecured syndicated term credit facilities. We had no interest rate swaps outstanding in 2004 or 2003.

(F) CREDIT RISK MANAGEMENT

A substantial portion of our accounts receivable are with counterparties in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We assess the financial strength of our counterparties, including those involved in marketing and other commodity arrangements, and we limit the total exposure to individual counterparties. As well, a number of our contracts contain provisions that allow us to demand the posting of collateral in the event downgrades to non-investment grade credit ratings occur. Credit risk, including credit concentrations, is routinely reported to our Risk Management Committee. We also use standard agreements that allow for the netting of exposures associated with a single counterparty. We believe this minimizes our overall credit risk.

7. Long-term Debt And Short-term Borrowings

	2004	2003
Acquisition Credit Facilities (US$1.5 billion drawn) (a)	1,806	-
Term Credit Facilities (US$72 million drawn) (b)	87	-
Notes, due 2004 (c)	-	291
Debentures, due 2006 (d)	93	98
Medium Term Notes, due 2007 (e)	150	150
Medium Term Notes, due 2008 (f)	125	125
Notes, due 2013 (US$500 million) (g)	602	646
Notes, due 2028 (US$200 million) (h)	241	258
Notes, due 2032 (US$500 million) (i)	602	646
Subordinated Debentures, due 2043 (US$460 million) (j)	553	594
Preferred Securities, due 2048 (US$217 million) (k)	-	281
	4,259	3,089
Less: Current Portion of Long-Term Debt (c) (k)	-	(572)
	4,259	2,517

(A) ACQUISITION CREDIT FACILITIES

Nexen has committed, unsecured, non-revolving credit facilities totalling US$2 billion. The credit facilities include a bridge facility in the amount of US$1.5 billion, which was advanced on December 1, 2004 and used to fund a portion of the purchase price for the acquisition of EnCana (UK) Limited and a development facility in the amount of US$500 million, which may be drawn upon to finance a portion of our share of the costs for the development and operation of the acquired assets.

The credit facilities provide that the bridge facility shall not exceed US$750 million by November 2005 with the balance to be repaid by May 2007. The credit facilities also provide that the development facility be repaid by November 2007, unless this date is extended to May 2008. Optional repayments may be made by Nexen at any time with notice. Borrowings are available as US-dollar base rate loans, LIBOR-based loans, Canadian bankers' acceptances and Canadian prime rate loans. Interest is payable monthly at a floating rate. During 2004, the weighted average interest rate on the acquisition credit facilities was 3.2%.

Amounts due November 2005 with respect to the bridge facility have not been included in current liabilities as we are able to refinance this amount with our term credit facilities, if need be.

(B) TERM CREDIT FACILITIES

Nexen has committed, unsecured, revolving term credit facilities totalling $1,656 million, $410 million of which is available until 2008 and $1,246 million until 2009. At December 31, 2004, US$72 million was drawn on these facilities. The lenders have the option to extend the terms annually. Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime loans or US-dollar base rate loans. Interest is payable monthly at a floating rate. During 2004, the weighted average interest rate was 3.2% (2003—2.0%).

(C) NOTES, DUE 2004

During February 2004, we repaid US$225 million of notes.

(D) DEBENTURES, DUE 2006

During November 1996, we issued $100 million of unsecured 10-year redeemable debentures. Interest is payable semi-annually at a rate of 6.85% and the principal is to be repaid in November 2006. In December 1996, $50 million of this obligation was effectively converted through a currency exchange contract with a Canadian chartered bank to a US$37 million liability bearing interest at 6.75% for the term of the debentures. We may redeem part or all of the debentures at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the debentures plus 0.1%.

(E) MEDIUM TERM NOTES, DUE 2007

During July 1997, we issued $150 million of notes. Interest is payable semi-annually at a rate of 6.45% and the principal is to be repaid in July 2007. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(F) MEDIUM TERM NOTES, DUE 2008

During October 1997, we issued $125 million of notes. Interest is payable semi-annually at a rate of 6.3% and the principal is to be repaid in June 2008. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(G) NOTES, DUE 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05% and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%.

(H) NOTES, DUE 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4% and the principal is to be repaid in May 2028. We may redeem part or all of the notes any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.25%.

(I) NOTES, DUE 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875% and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.375%.

(J) SUBORDINATED DEBENTURES, DUE 2043
During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly in cash at a rate of 7.35% and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time on or after November 8, 2008. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(K) PREFERRED SECURITIES, DUE 2048
During March 1998, we issued US$217 million of preferred securities. The securities were redeemed at par on February 9, 2004. Interest was payable quarterly at a rate of 9.375%.

(L) DEBT REPAYMENTS

2005	903
2006	93
2007	1,075
2008	190
2009	-
Thereafter	1,998
Total Debt Repayments	**4,259**

(M) DEBT COVENANTS
Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2004, we were in compliance with all covenants.

(N) SHORT-TERM BORROWINGS
Nexen has unsecured operating loan facilities of approximately $349 million, of which $100 million was drawn (US$83 million) at December 31, 2004. Interest is payable at floating rates. During 2004, the weighted average interest rate on our short-term borrowings was 2.9% (2003—2.4%).

(O) INTEREST EXPENSE

	2004	2003	2002
Long-Term Debt	182	204	206
Other	12	8	6
Total	194	212	212
Less: Capitalized	(51)	(43)	(31)
Total Interest Expense	**143**	**169**	**181**

Capitalized interest relates to and is included as part of the cost of oil and gas and Syncrude properties. The capitalization rates are based on our weighted-average cost of borrowings.

8. Asset Retirement Obligations

Changes in carrying amounts of the asset retirement obligations associated with our property, plant and equipment are as follows:

	2004	2003
Balance at Beginning of Year	323	390
Obligations Assumed with Development Activities	12	6
Obligations Assumed with Business Acquisition	134	-
Obligations Discharged with Disposed Properties	(4)	(27)
Expenditures Made on Asset Retirements	(31)	(20)
Accretion	17	22
Revisions to Estimates	24	(19)
Effect of Foreign Exchange	(7)	(29)
Balance at End of Year[1]	**468**	**323**

Note:
1 Obligations due within 12 months of $47 million (2003—$18 million) have been included in accounts payable and accrued liabilities.

Our total estimated undiscounted asset retirement obligations amount to $770 million ($514 million—December 31, 2003). We have discounted the total estimated asset retirement obligations using a weighted-average, credit-adjusted risk-free rate of 5.7%. Approximately $121 million included in our asset retirement obligations will be settled over the next five years. The remaining obligations settle beyond five years and will be funded by future cash flows from our operations.

We own interests in assets for which the fair value of the asset retirement obligations cannot be reasonably determined because the assets currently have an indeterminate life and we cannot determine when remediation activities would take place. These assets include our interest in Syncrude's upgrader and sulphur pile.

The estimated future recoverable reserves at Syncrude are significant and given the long life of this asset, we are unable to determine when asset retirement activities would take place. Furthermore, the Syncrude plant can continue to run indefinitely with ongoing maintenance activities.

The retirement obligations for these assets will be recorded in the first year in which the lives of the assets are determinable.

9. Shareholders' Equity

(A) AUTHORIZED CAPITAL

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

(B) ISSUED COMMON SHARES AND DIVIDENDS

(thousands of shares)	2004	2003	2002
Beginning of Year	125,606	122,966	121,202
Issue of Common Shares for Cash:			
Exercise of Stock Options	2,951	1,964	1,090
Dividend Reinvestment Plan	448	476	500
Employee Flow-through Shares	195	200	174
End of Year	**129,200**	**125,606**	**122,966**
Dividends per Common Share ($/share)	0.40	0.325	0.30
Cash Consideration (Cdn$ millions)			
Exercise of Stock Options	93	50	27
Dividend Reinvestment Plan	21	15	17
Employee Flow-through Shares	10	8	7
	124	**73**	**51**

At December 31, 2004, there were 689,937 common shares (2003—1,307,305; 2002—1,783,968) reserved for issuance under the Dividend Reinvestment Plan.

(C) STOCK OPTIONS

In May 2004, our shareholders approved the modification of our stock option plan to a tandem option plan by including a cash feature. The tandem options give the holders a right to either purchase common shares at the exercise price or to receive cash payments equal to the excess of the market value of the common shares over the exercise price.

Similar to our stock appreciation rights, we use the intrinsic-value method to recognize compensation expense associated with our tandem options. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding.

Upon modification of the stock option plan, we were required to recognize an obligation for our tandem options. This obligation represented the difference between the market value of our common shares and the weighted-average exercise price of the options. As a result, we recognized an obligation of $85 million for the graded vested portion of the 6.3 million outstanding options on June 30, 2004. In the second quarter, a one-time, non-cash charge of $82 million was included in general and administrative expense, net of $3 million previously expensed in respect of our original stock options.

Following the introduction of the *American Jobs Creation Act of 2004* in the US, stock options awarded to our US employees on or after December 1, 2004 do not include a tandem option cash feature. We use the fair-value method to recognize compensation expense associated with these options. The expense is recognized over the vesting period of the options with a corresponding increase to contributed surplus. This resulted in compensation expense in 2004 of $0.1 million which was included in general and administrative expense.

We have granted options to purchase common shares to directors, officers and employees. Each option permits the holder to purchase one Nexen common share at the stated exercise price. Options granted prior to February 2001 vest over 4 years and are exercisable on a cumulative basis over 10 years. Options granted after February 2001 vest over 3 years and are exercisable on a cumulative basis over 5 years. At the time of grant, the exercise price equals the market price. The following options have been granted:

	2004		2003		2002	
	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)
Balance at Beginning of Year	9,203	34	9,476	30	8,831	30
Granted	2,112	51	1,877	44	1,788	31
Exercised for stock	(2,951)	30	(1,964)	28	(1,090)	25
Surrendered for cash	(144)	34	-	-	-	-
Forfeited	(82)	33	(186)	32	(53)	30
Balance at End of Year	**8,138**	**39**	**9,203**	**34**	**9,476**	**30**
Options Exercisable at End of Year	4,227	34	5,067	30	5,113	29
Common Shares Reserved for Issuance Under the Stock Option Plan	9,586		9,788		9,760	

The range of exercise prices of options outstanding and exercisable at December 31, 2004 is as follows:

	Outstanding Options			Exercisable Options	
	Number of Options (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Years to Expiry (years)	Number of Options (thousands)	Weighted Average Exercise Price ($/option)
$15.00 to $19.99	132	18	4	132	18
$20.00 to $24.99	182	24	2	182	24
$25.00 to $29.99	768	27	4	641	27
$30.00 to $34.99	1,772	33	3	1,326	33
$35.00 to $39.99	1,330	36	6	1,324	36
$40.00 to $44.99	1,850	43	4	622	43
$45.00 to $49.99	25	48	4	-	-
$50.00 to $54.99	2,079	51	5	-	-
Total Options	**8,138**			**4,227**	

In previous periods, we estimated the fair value of stock options issued using the Generalized Black-Scholes option pricing model under the following assumptions:

	2003	2002
Weighted-Average Fair Value ($/option)	10.10	9.08
Risk-Free Interest Rate (%)	3.6	3.6
Estimated Hold Period Prior to Exercise (years)	3	3
Volatility in the Price of Nexen's Common Shares (%)	30	35
Dividends per Common Share ($/share)	0.40	0.30

The following shows pro forma net income and earnings per common share had we applied the fair-value method to account for all stock options outstanding that were granted up to December 31, 2002. Stock options granted after that date have been expensed as general and administrative costs.

	2003	2002
Fair Value of Stock Options Granted	25	22
Less: Fair Value of Stock Options Expensed	(1)	-
	24	22
Net Income Attributable to Common Shareholders		
As Reported	578	409
Pro Forma	554	387
Earnings Per Common Share ($/share)		
Basic as Reported	4.67	3.34
Pro Forma	4.48	3.16
Diluted as Reported	4.63	3.30
Pro Forma	4.44	3.13

(D) STOCK APPRECIATION RIGHTS

Under our stock appreciation rights (StARs) plan established in 2001, employees are entitled to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The vesting period and other terms of the plan are similar to the stock option plan. The total rights granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares. At the time of grant, the exercise price equals the market price. The following stock appreciation rights have been granted:

	2004		2003		2002	
	StARs (thousands)	Weighted Average Exercise Price ($/right)	StARs (thousands)	Weighted Average Exercise Price ($/right)	StARs (thousands)	Weighted Average Exercise Price ($/right)
Balance at Beginning of Year	2,404	37	1,812	33	915	31
Granted	1,304	51	1,017	43	908	34
Exercised for Cash	(433)	33	(363)	32	(3)	31
Forfeited	(57)	37	(62)	32	(8)	31
Balance at End of Year	**3,218**	**43**	**2,404**	**37**	**1,812**	**33**
Rights Exercisable at End of Year	**1,011**	**36**	**495**	**33**	**306**	**31**

The range of exercise prices of stock appreciation rights outstanding and exercisable at December 31, 2004 is as follows:

	Outstanding StARs			Exercisable StARs	
	Number of StARs (thousands)	Weighted Average Exercise Price ($/right)	Weighted Average Years to Expiry (years)	Number of StARs (thousands)	Weighted Average Exercise Price ($/right)
$30.00 to $34.99	999	33	3	714	33
$35.00 to $39.99	5	38	3	2	38
$40.00 to $44.99	909	44	4	295	44
$45.00 to $49.99	14	48	4	-	-
$50.00 to $54.99	1,290	51	5	-	-
$55.00 to $59.99	1	55	4	-	-
Total StARs	**3,218**			**1,011**	

10. Earnings Per Common Share

We calculate basic earnings per common share from continuing operations using net income from continuing operations divided by the weighted-average number of common shares outstanding. We calculate basic earnings per common share using net income and the weighted-average number of common shares outstanding. We calculate diluted earnings per common share from continuing operations and diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

(millions of shares)	2004	2003	2002
Weighted-average number of common shares outstanding	128.6	123.8	122.4
Shares issuable pursuant to stock options	6.5	6.2	8.1
Shares to be purchased from proceeds of stock options	(4.8)	(5.1)	(6.7)
Weighted-average number of diluted common shares outstanding	**130.3**	**124.9**	**123.8**

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2004, we excluded 174,100 options (2003—2,817,023; 2002—46,167), because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding stock options were the only potential dilutive instruments.

11. Discontinued Operations

During the fourth quarter of 2004, we concluded production from our Buffalo field, offshore Australia as anticipated. The results of our operations in Australia have been treated as discontinued operations, as we have no plans to continue operations in the country. Scheduled remediation and abandonment of the field has commenced and is expected to be complete by the end of 2005. We expect no gain or loss on abandonment as the expected asset retirement obligations have been fully accrued.

During the third quarter of 2003, we sold certain non-core conventional light oil properties in southeast Saskatchewan in Canada. Net proceeds were $268 million and there was no gain or loss on the sale.

The results of operations from these properties in Australia and Canada are detailed below and shown as discontinued operations in our Consolidated Statement of Income.

	2004	2003			2002		
	Australia	Australia	Canada	Total	Australia	Canada	Total
Revenues							
Net Sales	75	64	66	130	165	100	265
Expenses							
Operating	53	30	16	46	50	25	75
General and Administration	-	-	-	-	1	-	1
Depreciation, Depletion, Amortization and Impairment	9	22	20	42	53	35	88
Exploration	-	1	1	2	3	8	11
Income before Income Taxes	13	11	29	40	58	32	90
Current Income Taxes	-	(4)	-	(4)	16	-	16
Future Income Taxes	-	2	14	16	3	18	21
Net Income	**13**	**13**	**15**	**28**	**39**	**14**	**53**
Earnings per Common Share ($/share)							
Basic (Note 10)	0.10	0.10	0.12	0.22	0.32	0.11	0.43
Diluted (Note 10)	0.10	0.10	0.12	0.22	0.32	0.11	0.43

Assets and liabilities on the Consolidated Balance Sheet include the following amounts for our discontinued operations in Australia. There are no assets and liabilities associated with our Saskatchewan properties on our Consolidated Balance Sheet at December 31, 2004 and 2003.

	December 31 2004	December 31 2003
Cash and Cash Equivalents	1	2
Accounts Receivable	8	8
Inventories and Supplies	-	13
Other Current Assets	1	1
Property, Plant and Equipment	-	4
Accounts Payable and Accrued Liabilities	25	1
Asset Retirement Obligations	-	34

12. Commitments, Contingencies And Guarantees

	2005	2006	2007	2008	2009	Thereafter
Operating leases	31	27	26	23	22	119
Transportation commitments	366	126	74	51	33	130
	397	153	100	74	55	249

We have a number of lawsuits and claims pending including income tax reassessments (see Note 15), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

During 2004, total rental expense was $45 million (2003—$49 million; 2002—$47 million).

From time to time we enter into certain types of contracts that require us to indemnify parties against possible third party claims particularly when these contracts relate to divestiture transactions. On occasion we may provide routine indemnifications. The terms of such obligations vary and generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. Our Risk Management Committee actively monitors our exposure to the above risks and obtains insurance coverage to satisfy potential or future claims as necessary. We believe that payments, if any, related to such matters would not have a material adverse effect on our liquidity, financial condition or results of operations.

13. Pension And Other Post Retirement Benefits

Nexen has contributory and non-contributory defined benefit and defined contribution pension plans, which together cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our share of this plan. Under these defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation.

(A) DEFINED BENEFIT PENSION PLANS

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

	2004		2003	
	Nexen	Syncrude	Nexen	Syncrude
Change in Projected Benefit Obligation (PBO)				
Beginning of Year	192	79	164	68
Service Cost	8	3	7	3
Interest Cost	12	5	11	4
Plan Participants' Contributions	2	-	2	-
Actuarial Loss	10	7	14	6
Benefits Paid	(7)	(3)	(6)	(2)
End of Year[1]	**217**	**91**	**192**	**79**
Change in Fair Value of Plan Assets				
Beginning of Year	154	44	127	37
Actual Return on Plan Assets	16	5	15	7
Employer's Contribution	6	4	16	2
Plan Participants' Contributions	2	-	2	-
Benefits Paid	(7)	(3)	(6)	(2)
End of Year	**171**	**50**	**154**	**44**
Reconciliation of Funded Status				
Funded Status[2]	(46)	(41)	(38)	(35)
Unamortized Transitional Obligation	1	-	1	-
Unamortized Prior Service Costs	4	-	5	-
Unamortized Net Actuarial Loss	30	30	26	25
Pension Liability	**(11)**	**(11)**	**(6)**	**(10)**
Pension Liability Recognized				
Deferred Charges and Other Assets	13	-	15	-
Accounts Payable and Accrued Liabilities	(1)	(2)	(1)	(2)
Other Deferred Credits and Liabilities	(23)	(9)	(20)	(8)
Pension Liability	**(11)**	**(11)**	**(6)**	**(10)**
Assumptions (%)				
Accrued Benefit Obligation at December 31				
Discount Rate	6.00	5.75	6.25	6.00
Long-Term Rate of Employee Compensation Increase	4.00	4.00	4.00	4.00
Benefit Cost for Year Ended December 31[3]				
Discount Rate	6.25	6.00	6.75	6.50
Long-Term Rate of Employee Compensation Increase	4.00	4.00	4.00	4.00
Long-Term Annual Rate of Return on Plan Assets[4]	7.00	8.50	7.00	9.00

Notes:

1 Nexen's employee pension plan's accumulated benefit obligation (the projected benefit obligation excluding future salary increases) was $159 million at December 31, 2004. Nexen's supplemental pension plan's accumulated benefit obligation was $23 million at December 31, 2004. Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was $67 million at December 31, 2004.

2 Includes unfunded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. At December 31, 2004, the PBO for supplemental benefits was $34 million (2003—$29 million).

3 The assumptions have been used to calculate the recognized expense for Nexen. There were no changes to the assumptions between the measurement date and December 31, 2004. Syncrude's measurement date was December 31, 2004.

4 The long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities.

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2004	2003	2002
Nexen			
Cost of Benefits Earned by Employees	8	7	7
Interest Cost on Benefits Earned	12	11	10
Actual Return on Plan Assets	(16)	(15)	7
Actuarial (Gains) Losses	10	14	(11)
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	14	17	13
Difference Between Actual and Expected Return	5	7	(16)
Difference Between Actual and Recognized Actuarial Gains (Losses)	(10)	(15)	10
Difference Between Actual and Recognized Past Service Costs	1	1	1
Net Pension Expense	10	10	8
Syncrude			
Cost of Benefits Earned by Employees	3	3	3
Interest Cost on Benefits Earned	5	4	4
Actual Return on Plan Assets	(5)	(7)	3
Actuarial (Gains) Losses	7	6	-
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	10	6	10
Difference Between Actual and Expected Return	1	4	(7)
Difference Between Actual and Recognized Actuarial Gains (Losses)	(6)	(5)	1
Difference Between Actual and Recognized Past Service Costs	-	-	-
Net Pension Expense	5	5	4
Total	**15**	**15**	**12**

(B) PLAN ASSET ALLOCATION AT DECEMBER 31

Our investment goal for the assets in our defined benefit pension plan is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies mandated by our Board of Directors and Pension Committee. Nexen's investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations, that are traded on recognized stock exchanges. A fund's market value may not exceed a maximum in any one issuer at the time of purchase, as set out by our investment policy provided to fund managers. Allowable and prohibited investment types are also prescribed in Nexen's investment policy.

Syncrude's pension plan is governed and administered separately from ours. Syncrude's investment assets are subject to a similar investment goal, policy and strategy.

(%)	Expected 2005	2004	2003
Nexen			
Equity Securities	60	60	52
Debt Securities	40	40	40
Real Estate	-	-	-
Other	-	-	8
Total	**100**	**100**	**100**
Syncrude			
Equity Securities	70	70	72
Debt Securities	30	30	28
Real Estate	-	-	-
Other	-	-	-
Total	**100**	**100**	**100**

(C) DEFINED CONTRIBUTION PENSION PLANS

Under these plans, pension benefits are based on plan contributions. During 2004, Canadian pension expense for these plans was $4 million (2003—$4 million; 2002—$3 million). During 2004, US pension expense for these plans was $3 million (2003—$3 million; 2002—$3 million).

(D) POST-RETIREMENT BENEFITS

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. These costs are fully accrued as compensation in the period employees work; however, these future obligations are not funded. The present value of Nexen employees' future post retirement benefits in 2004 was $5 million (2003—$5 million). Nexen's share of post-retirement and post-employment benefits related to Syncrude in 2004 was $7 million (2003—$6 million).

(E) EMPLOYER FUNDING CONTRIBUTIONS AND BENEFIT PAYMENTS

Canadian regulators have prescribed funding requirements for our defined benefit plans. Our funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law. For our defined contribution plans, we always match the employee contribution and no further obligation exists. Our funding contributions for the defined benefit plans are:

	Expected 2005	2004	2003
Defined Benefit Contributions			
Nexen	1	6	16
Syncrude	5	4	2
Total Funding Contributions	**6**	**10**	**18**

Our most recent funding valuation was prepared as of June 30, 2004. Our next funding valuation is required by June 30, 2007. Syncrude's most recent funding valuation was prepared as of January 1, 2004. Syncrude's next funding valuation is January 1, 2007.

Our total benefit payments in 2004 were $7 million (2003—$6 million). Our share of Syncrude's total benefit payments in 2004 was $3 million (2003—$2 million). Our estimated future payments are as follows:

	Defined Benefit		Other	
	Nexen	Syncrude	Nexen	Syncrude
2005	8	3	1	-
2006	8	3	1	-
2007	9	3	1	-
2008	10	4	1	-
2009	10	4	2	-
2010 - 2014	66	26	12	2

14. Marketing And Other

	2004	2003	2002
Marketing Revenue, Net	623	568	496
Unrealized Gains on Crude Oil Put Options	56	-	-
Interest	12	9	7
Foreign Exchange Gains (Losses)	(13)	6	(3)
Gains (Losses) on Disposition of Assets[1]	24	-	(8)
Other[2]	27	27	4
Total Marketing and Other	**729**	**610**	**496**

Notes:

1 In 2004, gains on disposition of assets resulted from the sale of minor oil and gas assets by our Canadian oil and gas business. The net loss in 2002 includes a gain of $13 million on the sale of our asphalt operation in Moose Jaw, Saskatchewan and a loss of $21 million on the sale of a non-operated property by our Canadian oil and gas business.

2 In 2004, other includes $10 million (2003—$12 million) of business interruption proceeds received from our insurers. The proceeds result from damage sustained in the Gulf of Mexico during tropical storm Isidore and Hurricane Lili in the third and fourth quarters of 2002.

15. Income Taxes

(A) TEMPORARY DIFFERENCES

	2004		2003	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Property, Plant and Equipment, Net	31	1,960	26	519
Tax Losses Carried Forward	277	-	69	-
Deferred Income	-	171	-	200
Recoverable Taxes	25	-	13	-
Other	-	-	-	1
Total	**333**	**2,131**	**108**	**720**

(B) CANADIAN AND FOREIGN INCOME TAXES

	2004	2003	2002
Income from Continuing Operations before Income Taxes:			
Canadian	144	(265)	36
Foreign	1,003	956	483
	1,147	**691**	**519**
Provision for Income Taxes:			
Current			
Canadian	6	5	4
Foreign	242	209	203
	248	**214**	**207**
Future			
Canadian	47	(136)	(8)
Foreign	72	63	(36)
	119	**(73)**	**(44)**
Total Provision for Income Taxes	**367**	**141**	**163**

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen and the United States and include Yemen cash taxes of $227 million (2003—$201 million; 2002—$207 million).

(C) RECONCILIATION OF EFFECTIVE TAX RATE TO THE CANADIAN FEDERAL TAX RATE

	2004	2003	2002
Income before Income Taxes From Continuing Operations	1,147	691	519
Provision for Income Taxes Computed at the Canadian Statutory Rate	396	256	205
Add (Deduct) the Tax Effect of:			
Royalties and Rentals to Provincial Governments	37	44	45
Resource Allowance and Provincial Tax Rebates	(42)	(50)	(60)
Lower Tax Rates on Foreign Operations	(22)	(48)	(32)
Additional Canadian Tax on Canadian Resource Income	11	11	7
Lower Tax Rates on Capital Gains	-	-	(6)
Federal and Provincial Capital Tax	6	4	4
Revaluation of Future Income Tax Liabilities for Reductions in Statutory Rates	(15)	(76)	(1)
Other	(4)	-	1
Provision for Income Taxes	**367**	**141**	**163**

During the last three years, the federal and some provincial governments in Canada reduced statutory income tax rates. In 2004, this reduced our liability and provision for future income taxes by $15 million (2003—$76 million; 2002—$1 million).

(D) AVAILABLE UNUSED TAX LOSSES AND TAX CONTINGENCIES

At December 31, 2004, we had unused tax losses totalling $702 million mostly from our UK operations. At December 31, 2003, we had unused tax losses totalling $195 million mostly from our US operations.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some that may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an adequate provision for income taxes based on available information.

At the time of acquisition, Wascana had outstanding taxation issues in dispute from prior taxation years. Wascana disagreed with issues raised and has filed notices of objection. The value of the tax pools acquired at the time of acquisition reflected our evaluation of the potential impact of these issues.

16. Cash Flows

(A) CHARGES AND CREDITS TO INCOME NOT INVOLVING CASH

	2004	2003	2002
Depreciation, Depletion, Amortization and Impairment	744	995	632
Stock Based Compensation	74	4	-
Loss (Gain) on Disposition of Assets	(24)	-	8
Future Income Taxes	119	(73)	(44)
Unrealized Gains on Crude Oil Put Options	(56)	-	-
Non-Cash Items included in Discontinued Operations	9	60	120
Unamortized Issue Costs on Preferred Securities Redemption	11	28	-
Other	26	4	8
	903	1,018	724

(B) CHANGES IN NON-CASH WORKING CAPITAL

	2004	2003	2002
Accounts Receivable	(454)	(488)	(388)
Inventories and Supplies	(106)	(45)	(73)
Other Current Assets	44	(59)	(6)
Accounts Payable and Accrued Liabilities	650	242	411
Other	(12)	12	17
Total Change in Non-Cash Working Capital	**122**	**(338)**	**(39)**
Relating to:			
Operating Activities	(122)	(320)	(46)
Investing Activities	244	(18)	7
Total Change in Non-Cash Working Capital	**122**	**(338)**	**(39)**

(C) OTHER CASH FLOW INFORMATION

	2004	2003	2002
Interest Paid	190	197	189
Income Taxes Paid	249	211	238

In 2004, other operating activity cash outflows include $144 million for the purchase of crude oil put options.

17. Deferred Charges And Other Assets

	2004	2003
Crude Oil Put Options (Note 6)	200	-
Long-Term Marketing Derivative Contracts (Note 6)	91	63
Defined Benefit Pension Plan Asset (Note 13)	13	15
Deferred Financing Costs	67	62
Other	58	24
Total	**429**	**164**

18. Operating Segments And Related Information

Nexen has the following operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily offshore West Africa and in Colombia. Oil and gas also includes our marketing operations. Marketing sells our own crude oil and natural gas, markets third party crude oil and natural gas and engages in energy trading.

Syncrude: We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from mining bitumen in the oil sands in northern Alberta, Canada.

Chemicals: We manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine, acid and caustic soda. We produce sodium chlorate at five facilities in Canada and one in Brazil. We produce chlorine, acid and caustic soda at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

2004 OPERATING AND GEOGRAPHIC SEGMENTS

	Oil and Gas									
(Cdn$ millions)	Yemen	Canada	US	UK[2]	Other Countries[3]	Marketing	Syncrude[1]	Chemicals	Corporate and Other	Total
Net Sales[4]	921	622	811	36	73	14	321	378[5]	-	3,176
Marketing and Other	5	28	11	-	2	623	-	5	55[6]	729
Total Revenues	926	650	822	36	75	637	321	383	55	3,905
Less: Expenses										
Operating	109	156	106	6	7	16	125	237	-	762
Depreciation, Depletion, Amortization and Impairment	169	198	258	18	18	10	18	37	18	744
Transportation and Other	5	15	-	-	-	466	12	41	25	564
General and Administrative	4	42	30	-	47	58	1	28	89	299
Exploration	2	21	138	3	82[7]	-	-	-	-	246
Interest	-	-	-	-	-	-	-	-	143	143
Income (Loss) from Continuing Operations before Income Taxes	637	218	290	9	(79)	87	165	40	(220)	1,147
Less: Provision for (Recovery of) Income Taxes[8]	222	78	104	4	1	28	47	13	(130)	367
Net Income (Loss) from Continuing Operations	415	140	186	5	(80)	59	118	27	(90)	780
Add: Net Income from Discontinued Operations	-	-	-	-	13[9]	-	-	-	-	13
Net Income (Loss)	**415**	**140**	**186**	**5**	**(67)**	**59**	**118**	**27**	**(90)**	**793**
Identifiable Assets	**564**	**1,979**	**1,359**	**4,446**	**218**	**2,030[10]**	**912**	**497**	**378**	**12,383**
Capital Expenditures										
Development and Other	267	491	267	53	24	4	214	58	33	1,411
Exploration	19	46	133	4	64	-	-	-	-	266
Proved Property Acquisitions	-	4	-	-	-	-	-	-	-	4
Total Capital Expenditures	**286**	**541**	**400**	**57**	**88**	**4**	**214**	**58**	**33**	**1,681**
Property, Plant and Equipment										
Cost	2,038	3,463	2,249	3,499	535	157	1,030	815	201	13,987
Less: Accumulated DD&A	1,550	1,615	1,037	16	408	64	155	409	90	5,344
Net Book Value[4]	**488**	**1,848**	**1,212**	**3,483**	**127**	**93**	**875**	**406**	**111**	**8,643**
Goodwill										
Cost	-	-	-	339	-	60	-	-	-	399
Less: Accumulated DD&A	-	-	-	-	-	24	-	-	-	24
Net Book Value	**-**	**-**	**-**	**339**	**-**	**36**	**-**	**-**	**-**	**375**

Notes:

1 Syncrude is considered a mining operation for US reporting purposes. Property, plant and equipment at December 31, 2004 includes mineral rights of $6 million.

2 On December 1, 2004 we acquired EnCana (UK) Limited (see Note 2).

3 Includes results of operations from producing activities in Nigeria, Colombia, and Australia.

4 Net sales made from all segments originating in Canada: $ 1,242
Property, plant and equipment located in Canada: $ 3,198

5 Net sales for our chemicals operations include:

Canada	$ 285
United States	33
Brazil	60
	$ 378

6 Includes interest income of $12 million, foreign exchange losses of $13 million and unrealized mark-to-market gains on crude oil put options of $56 million.

7 Includes exploration activities primarily in Nigeria and Colombia.

8 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

9 In the fourth quarter of 2004, we concluded production activities in Australia. These results are shown as discontinued operations (Note 11).

10 Approximately 81% of Marketing's identifiable assets are accounts receivable and inventories.

2003 OPERATING AND GEOGRAPHIC SEGMENTS

(Cdn$ millions)	Oil and Gas Yemen	Oil and Gas Canada	Oil and Gas US	Oil and Gas Other Countries[2]	Marketing[3]	Syncrude[1]	Chemicals	Corporate and Other	Total
Net Sales[4]	827	609	707	65	21	240	375[5]	-	2,844
Marketing and Other	6	5	14	-	568	-	2	15[6]	610
Total Revenues	833	614	721	65	589	240	377	15	3,454
Less: Expenses									
Operating	92	143	86	15	22	123	240	-	721
Depreciation, Depletion, Amortization and Impairment	168	490[7]	207	38	15	14	46	17	995
Transportation and Other	5	4	-	-	398	11	42	29	489
General and Administrative	5	27	13	20	43	1	21	60	190
Exploration	17	34	89	59[8]	-	-	-	-	199
Interest	-	-	-	-	-	-	-	169	169
Income (Loss) from Continuing Operations before Income Taxes	546	(84)	326	(67)	111	91	28	(260)	691
Less: Provision for (Recovery of) Income Taxes[9]	191	(96)	115	(1)	39	25	10	(142)	141
Net Income (Loss) from Continuing Operations	355	12	211	(66)	72	66	18	(118)	550
Add: Net Income from Discontinued Operations	-	15[10]	-	13[11]	-	-	-	-	28
Net Income (Loss)	**355**	**27**	**211**	**(53)**	**72**	**66**	**18**	**(118)**	**578**
Identifiable Assets	**574**	**2,176**	**1,446**	**197**	**1,518[12]**	**719**	**475**	**612**	**7,717**
Capital Expenditures									
Development and Other	219	259	249	25	1	195	24	29	1,001
Exploration	34	51	147	97	-	-	-	-	329
Proved Property Acquisitions	-	-	164[13]	-	-	-	-	-	164
Total Capital Expenditures	**253**	**310**	**560**	**122**	**1**	**195**	**24**	**29**	**1,494**
Property, Plant and Equipment									
Cost	1,898	2,951	2,153	534	158	821	774	168	9,457
Less: Accumulated DD&A	1,497	1,460	887	410	57	144	381	71	4,907
Net Book Value[4]	**401**	**1,491**	**1,266**	**124**	**101**	**677**	**393**	**97**	**4,550**
Goodwill									
Cost	-	-	-	-	60	-	-	-	60
Less: Accumulated DD&A	-	-	-	-	24	-	-	-	24
Net Book Value	**-**	**-**	**-**	**-**	**36**	**-**	**-**	**-**	**36**

Notes:

1 Syncrude is considered a mining operation for US reporting purposes. Property, plant and equipment at December 31, 2003 includes mineral rights of $6 million.

2 Includes results of operations from producing activities in Nigeria, Colombia and Australia.

3 Includes results of operations from a natural gas-fired generating facility in Alberta. In 2002, these results were included in Corporate and Other.

4 Net sales made from all segments originating in Canada: $ 1,218
Property, plant and equipment located in Canada: $ 2,566

5 Net sales for our chemicals operations include:

Canada	$ 282
United States	13
Brazil	80
	$ 375

6 Includes interest income of $9 million and foreign exchange gains of $6 million.

7 Includes impairment charge of $269 million as discussed in Note 5.

8 Includes exploration activities primarily in Nigeria, Colombia, Brazil and Equatorial Guinea.

9 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

10 In August 2003, we sold non-core conventional light oil assets in southeast Saskatchewan for net proceeds of $268 million. No gain or loss was recognized on the sale. These results are shown as discontinued operations (see Note 11).

11 In the fourth quarter of 2004, we concluded production activities in Australia. These results are shown as discontinued operations (see Note 11).

12 Approximately 80% of Marketing's identifiable assets are accounts receivable and inventories.

13 On March 27, 2003, we acquired the residual 40% interest in Aspen in the Gulf of Mexico for US$109 million.

2002 OPERATING AND GEOGRAPHIC SEGMENTS

(Cdn$ millions)	Oil and Gas				Marketing	Syncrude[1]	Chemicals	Corporate and Other[2]	Total
	Yemen	Canada	US	Other Countries[3]					
Net Sales[4]	789	556	296	78	-	245	367[5]	10	2,341
Marketing and Other	-	(19)[6]	-	-	496	-	2	17[7]	496
Total Revenues	789	537	296	78	496	245	369	27	2,837
Less: Expenses									
Operating	86	151	94	22	-	109	229	10	701
Depreciation, Depletion, Amortization and Impairment	149	218	133	46	8	13	52	13	632
Transportation and Other	-	-	3	-	423	6	40	3	475
General and Administrative	4	22	11	19	30	1	21	43	151
Exploration	21	30	82	45[8]	-	-	-	-	178
Interest	-	-	-	-	-	-	-	181	181
Income (Loss) from Continuing Operations before Income Taxes	529	116	(27)	(54)	35	116	27	(223)	519
Less: Provision for (Recovery of) Income Taxes[9]	188	41	(10)	(18)	12	37	9	(96)	163
Net Income (Loss) from Continuing Operations	341	75	(17)	(36)	23	79	18	(127)	356
Add: Net Income from Discontinued Operations	-	14[10]	-	39[11]	-	-	-	-	53
Net Income (Loss)	**341**	**89**	**(17)**	**3**	**23**	**79**	**18**	**(127)**	**409**
Identifiable Assets	**600**	**2,164**	**1,477**	**227**	**811[12]**	**543**	**542**	**301**	**6,665**
Capital Expenditures									
Development and Other	209	258	541	69	2	141	45	97[13]	1,362
Exploration	22	60	116	61	-	-	-	-	259
Proved Property Acquisitions	-	4	-	-	-	-	-	-	4
Total Capital Expenditures	**231**	**322**	**657**	**130**	**2**	**141**	**45**	**97**	**1,625**
Property, Plant and Equipment									
Cost	2,054	3,170	2,244	563	87	638	803	213	9,772
Less: Accumulated DD&A	1,646	1,169	992	426	41	142	355	57	4,828
Net Book Value[4]	**408**	**2,001**	**1,252**	**137**	**46**	**496**	**448**	**156**	**4,944**
Goodwill									
Cost	-	-	-	-	60	-	-	-	60
Less: Accumulated DD&A	-	-	-	-	24	-	-	-	24
Net Book Value	**-**	**-**	**-**	**-**	**36**	**-**	**-**	**-**	**36**

Notes:

1 Syncrude is considered a mining operation for US reporting purposes. Property, plant and equipment at December 31, 2002 includes mineral rights of $6 million.

2 Includes results of operations from a natural gas-fired generating facility in Alberta.

3 Includes results of operations from producing activities in Nigeria, Colombia and Australia.

4 Net sales made from all segments originating in Canada: $ 1,162
Property, plant and equipment located in Canada: $ 2,908

5 Net sales for our chemicals operations include:

Canada	$ 251
United States	56
Brazil	60
	$ 367

6 Includes a loss of $21 million on disposition of our non-operated oil and gas properties for proceeds of $14 million.

7 Includes interest income of $7 million, foreign exchange losses of $3 million and a gain of $13 million on disposition of our Moose Jaw Asphalt operation for proceeds of $27 million plus working capital.

8 Includes exploration activities primarily in Nigeria, Colombia and Brazil.

9 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

10 In August 2003, we sold non-core conventional light oil assets in southeast Saskatchewan for net proceeds of $268 million. No gain or loss was recognized on the sale. These results are shown as discontinued operations (see Note 11).

11 In the fourth quarter of 2004, we concluded production activities in Australia. These results are shown as discontinued operations (see Note 11).

12 Approximately 87% of Marketing's identifiable assets are accounts receivable and inventories.

13 Includes $67 million related to the buy out of the lease agreement related to the construction of a natural gas-fired generating facility in Alberta.

19. Differences Between Canadian And US Generally Accepted Accounting Principles

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

(A) CONSOLIDATED STATEMENT OF INCOME—US GAAP FOR THE THREE YEARS ENDED DECEMBER 31, 2004

(Cdn$ millions except per share amounts)	2004	2003	2002
Revenues			
Net Sales	3,176	2,844	2,341
Marketing and Other (ii); (ix); (x)	712	623	498
	3,888	3,467	2,839
Expenses			
Operating (iv)	771	727	701
Depreciation, Depletion, Amortization and Impairment (i)	786	1,108	685
Transportation and Other (ix)	539	489	483
General and Administrative (viii)	263	190	151
Exploration	246	199	178
Interest	143	169	181
	2,748	2,882	2,379
Income from Continuing Operations before Income Taxes	1,140	585	460
Provision for Income Taxes			
Current	248	214	207
Deferred (i) – (x)	117	(91)	(46)
	365	123	161
Net Income from Continuing Operations before Cumulative Effect of Changes in Accounting Principles	775	462	299
Net Income from Discontinued Operations (i)	13	6	53
Cumulative Effect of Changes in Accounting Principles, Net of Income Taxes (vii); (x)	-	(48)	-
Net Income—US GAAP[1]	**788**	**420**	**352**
Earnings Per Common Share ($/share)			
Basic (Note 10)			
Net Income from Continuing Operations	6.03	3.73	2.45
Net Income from Discontinued Operations	0.10	0.04	0.43
Cumulative Effect of Changes in Accounting Principles	-	(0.38)	-
	6.13	**3.39**	**2.88**
Diluted (Note 10)			
Net Income from Continuing Operations	5.95	3.70	2.41
Net Income from Discontinued Operations	0.10	0.04	0.43
Cumulative Effect of Changes in Accounting Principles	-	(0.38)	-
	6.05	**3.36**	**2.84**

Note:

1 **Reconciliation of Canadian and US GAAP Net Income:**

(Cdn$ millions)	2004	2003	2002
Net Income—Canadian GAAP	793	578	409
Impact of US Principles, Net of Income Taxes:			
Fair Value of Preferred Securities (x)	4	7	-
Depreciation, Depletion, Amortization and Impairment (i); (vii)	(42)	(92)	(53)
Stock Based Compensation included in Retained Earnings (viii)	36	-	-
Loss on Disposition (i)	-	(22)	-
Other (ii); (iv)	(3)	(3)	(4)
Cumulative Effect of Changes in Accounting Principles (vii); (x)	-	(48)	-
Net Income—US GAAP	**788**	**420**	**352**

(B) CONSOLIDATED BALANCE SHEET—US GAAP

(Cdn$ millions, except share amounts)	December 31 2004	December 31 2003
ASSETS		
Current Assets		
Cash and Cash Equivalents	74	1,087
Accounts Receivable (ii)	2,142	1,423
Inventories and Supplies	351	270
Other	42	79
Total Current Assets	2,609	2,859
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $5,792 (December 31, 2003–$5,330) (i); (iv); (vii)	8,638	4,583
Goodwill	375	36
Deferred Income Tax Assets	333	108
Deferred Charges and Other Assets (v)	384	117
TOTAL ASSETS	12,339	7,703
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-Term Borrowings	100	-
Current Portion of Long-Term Debt (x)	-	575
Accounts Payable and Accrued Liabilities (ii)	2,416	1,418
Accrued Interest Payable	34	44
Dividends Payable	13	12
Total Current Liabilities	2,563	2,049
Long-Term Debt (v)	4,214	2,470
Deferred Income Tax Liabilities (i) – (x)	2,101	678
Asset Retirement Obligations (vii)	421	305
Deferred Credits and Other Liabilities (vi)	148	70
Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2004–129,199,583 shares		
2003–125,606,107 shares	637	513
Contributed Surplus	-	1
Retained Earnings (i) – (x)	2,360	1,660
Accumulated Other Comprehensive Income (ii); (iii); (vi)	(105)	(43)
Total Shareholders' Equity	2,892	2,131
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	12,339	7,703

Commitments, Contingencies and Guarantees

(C) CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME—US GAAP FOR THE THREE YEARS ENDED DECEMBER 31, 2004

(Cdn$ millions)	2004	2003	2002
Net Income–US GAAP	788	420	352
Other Comprehensive Income, net of income taxes:			
Translation Adjustment (iii)	(72)	(127)	34
Unrealized Mark-to-Market Gain (Loss) (ii)	11	(7)	-
Minimum Unfunded Pension Liability (vi)	(1)	(1)	(2)
Comprehensive Income	726	285	384

(D) CONSOLIDATED STATEMENT OF CASH FLOWS

Under US principles, geological and geophysical costs in 2003 of $62 million and in 2002 of $80 million included in investing activities would be reported in operating activities. See Note 1(r) to our Consolidated Financial Statements.

Notes to the Consolidated US GAAP Financial Statements:

i. Under US principles, the liability method of accounting for income taxes was adopted in 1993. In Canada, the liability method was adopted in 2000. In 1997, we acquired certain oil and gas assets and the amount paid for these assets differed from the tax basis acquired. Under US principles, this difference was recorded as a deferred tax liability with an increase to property, plant and equipment rather than a charge to retained earnings. As a result:

- additional depreciation, depletion, amortization and impairment of $42 million (2003—$98 million; 2002—$53 million) was included in net income; and
- property, plant and equipment is higher under US GAAP by $29 million (December 31, 2003—$71 million).

During the third quarter of 2003, some of these assets were sold as described in Note 11. With the carrying value of these assets higher under US GAAP, the sale resulted in a loss on disposition of $22 million, net of income taxes of $10 million. This loss was included in our 2003 net income from discontinued operations disclosed on the Consolidated Statement of Income—US GAAP.

Included in depreciation, depletion, amortization and impairment expense for 2003 is an impairment charge of $315 million. The amount is higher under US GAAP as we have higher US GAAP carrying values for the assets impaired resulting from differences in adopting the liability method of accounting for income taxes as previously described.

ii. Under US principles, all derivative instruments are recognized on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met.

Cash flow hedges

Changes in the fair value of derivatives that are designated as cash flow hedges are recognized in earnings in the same period as the hedged item. Any fair value change in a derivative before that period is recognized on the balance sheet. The effective portion of that change is recognized in other comprehensive income with any ineffectiveness recognized in net income.

Future sale of oil and gas production: Included in accounts payable at December 31, 2003, was a $3 million loss on the forward contracts we used to hedge the commodity price risk on the future sale of a portion of our production from the Aspen field as described in Note 6. These contracts expired in March 2004. The losses ($2 million, net of income taxes), that were deferred in accumulated other comprehensive income (AOCI) at December 31, 2003, were recognized in net sales in 2004.

Future sale of gas inventory: Included in accounts payable at December 31, 2003, was $11 million of losses on the futures and basis swap contracts we used to hedge the commodity price risk on the future sale of our gas inventory as described in Note 6. These contracts effectively lock-in profits on our stored gas volumes. Losses of $8 million ($5 million, net of income taxes) related to the effective portion and deferred in AOCI at December 31, 2003, were recognized in marketing and other in 2004. Additionally, losses of $3 million ($2 million, net of income taxes), related to the ineffective portion, were recognized in marketing and other under US GAAP in 2003. Under Canadian GAAP, the ineffective portion was recognized in net income in 2004.

At December 31, 2004, gains of $6 million ($4 million, net of income taxes) were included in accounts receivable and deferred in AOCI until the underlying gas inventory is sold. The gains will be reclassified to marketing and other in 2005 as they settle over the next 12 months.

Fair value hedges

Both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value. The change in fair value of both are reflected in earnings. At December 31, 2004, we had no fair value hedges in place.

iii. Under US principles, exchange gains and losses arising from the translation of our net investment in self-sustaining foreign operations are included in comprehensive income. Additionally, exchange gains and losses, net of income taxes, from the translation of our US-dollar long-term debt designated as a hedge of our foreign net investment are included in comprehensive income. Cumulative amounts are included in AOCI in the Consolidated Balance Sheet—US GAAP.

iv. Under Canadian principles, we defer certain development costs and all pre-operating revenues and costs to property, plant and equipment. Under US principles, these costs have been included in operating expenses. As a result:
- operating expenses include pre-operating costs of $9 million ($6 million, net of income taxes) (2003—$4 million, net of income taxes of $2 million); and
- property, plant and equipment is lower under US GAAP by $15 million (December 31, 2003—$6 million).

v. Under US principles, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred charges and other assets. Discounts of $45 million (December 31, 2003—$47 million) have been included in long-term debt.

vi. Under US principles, the amount by which our accrued pension cost is less than the unfunded accumulated benefit obligation is included in AOCI and accrued pension liabilities. This amount was $6 million ($4 million, net of income taxes) at December 31, 2004 (December 31, 2003—$4 million ($3 million, net of income taxes)).

vii. On January 1, 2003 we adopted FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004 as described in Note 1. These standards are consistent except for the adoption date which resulted in our property, plant and equipment under US GAAP being lower by $19 million.

This change in accounting policy has been reported as a cumulative effect adjustment in the Consolidated Statement of Income—US GAAP as a loss of $37 million, net of income taxes of $25 million, on January 1, 2003.

viii. As described in Note 9(c), our existing stock option plan was modified to a tandem option plan. An obligation of $85 million was recognized for these tandem options. This resulted in a one-time, non-cash charge to net income of $54 million, net of tax in the second quarter of 2004. Under US principles, the modification of our stock option plan is accounted for by providing us with credit for the pro-forma expense previously disclosed for the stock options modified. The related pro-forma expense was $36 million, which is accounted for as an adjustment to retained earnings with a corresponding decrease to our one-time charge to net income.

ix. Under US principles, gains and losses on the disposition of assets are shown as other expense. Gains (losses) of $24 million (2003—$nil; 2002—$(8)) were reclassed from marketing and other to transportation and other.

x. In May 2003, FASB issued Statement No. 150, *Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity* that requires certain financial instruments, including our preferred securities, to be valued at fair value with changes in fair value recognized through net income.

(Cdn$ millions)	Gain (Loss)[1]	Tax	Net Gain (Loss)
Fair value change up to June 30, 2003[2]	(16)	5	(11)
Fair value change from July 1, 2003 to December 31, 2003[1]	12	(5)	7
Fair value change from January 1, 2004 to February 9, 2004[1,3]	4	-	4

Notes:
1 Included in marketing and other.
2 Reported as cumulative effect of a change in accounting principle.
3 Redemption date of preferred securities.

NEW ACCOUNTING PRONOUNCEMENTS

In November 2004, the Financial Accounting Standards Board (FASB) issued Statement 151, *Inventory Costs*. This statement amends ARB 43 to clarify that:

- abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage) should be recognized as current-period charges; and
- requires the allocation of fixed production overhead to inventory based on the normal capacity of the production facilities.

The provisions of this statement are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. We do not expect the adoption of this statement will have any material impact on our results of operations or financial position.

In December 2004, the FASB issued Statement 123(R), *Share-Based Payments*. This statement revises Statement 123, *Accounting for Stock-Based Compensation*, and supersedes APB Opinion 25, *Accounting for Stock Issued to Employees*.

Statement 123(R) requires all stock-based awards issued to employees to be measured at fair value and to be expensed in the income statement. This statement is effective for reporting periods beginning after June 15, 2005.

We are currently expensing stock-based awards issued to employees using the fair value method for equity based awards and the intrinsic method for liability based awards. Adoption of this standard will change our expense under US GAAP for tandem options and stock appreciation rights as these awards will be measured using the fair value method rather than the intrinsic method. We are currently evaluating the provisions of Statement 123(R) and have not yet determined the full impact this statement will have on our results of operations or financial position under US GAAP.

In December 2004, the FASB issued Statement 152, *Accounting for Real Estate*. This statement amends Statement 66, *Accounting for Sales of Real Estate*, to reference the financial accounting and reporting guidance for real estate time-sharing transactions that is provided in AICPA Statement of Position 04-2, *Accounting for Real Estate Time-Sharing Transactions*. This statement also amends FASB Statement 67, *Accounting for Costs and Initial Rental Operations of Real Estate Projects*, to state that the guidance for incidental operations and costs incurred to sell real estate projects does not apply to real estate time-sharing transactions. This statement is effective for financial statements with fiscal years beginning after June 15, 2005 and will not impact our results of operations or financial position.

In December 2004, the FASB issued Statement 153, *Exchanges of Nonmonetary Assets*, an amendment of APB Opinion 29, *Accounting for Nonmonetary Transactions*. This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. Under Statement 153, if a nonmonetary exchange of similar productive assets meets a commercial-substance criterion and fair value is determinable, the transaction must be accounted for at fair value resulting in recognition of any gain or loss. This statement is effective for nonmonetary transactions in fiscal periods that begin after June 15, 2005. The adoption of this statement will not have any material impact on our results of operation or financial position.

SUPPLEMENTARY FINANCIAL INFORMATION (UNAUDITED)

Quarterly Financial Data in Accordance with Canadian and US GAAP

	Quarter Ended							
	March 31		June 30		September 30		December 31	
(Cdn$ millions)	2004	2003	2004	2003	2004	2003	2004	2003
Net Sales as Previously Reported	743	806	779	726	837	716	866	660
Discontinued Operations–Australia	(28)	(28)	(21)	(17)	-	(19)	-	-
Net Sales[1]	**715**	**778**	**758**	**709**	**837**	**697**	**866**	**660**
Operating Profit as Previously Reported	319	410	283	288	391	304	383	(40)
Discontinued Operations–Australia	(4)	(9)	(5)	(1)	-	(4)	-	3
Operating Profit[1, 2, 3, 4]	**315**	**401**	**278**	**287**	**391**	**300**	**383**	**(37)**
Operating Profit is Comprised of:								
Oil and Gas	265	370	232	260	328	256	337	(54)
Syncrude	40	28	40	18	52	32	33	13
Chemicals	10	3	6	9	11	12	13	4
	315	**401**	**278**	**287**	**391**	**300**	**383**	**(37)**
Net Income (Loss) from Continuing Operations as Previously Reported–Canadian GAAP	192	244	143	258	220	178	242	(56)
Discontinued Operations–Australia	(4)	(6)	(5)	(8)	-	(1)	-	2
Changes in Accounting Polices[5]	(8)	(11)	-	(10)	-	(10)	-	(30)
Net Income (Loss) from Continuing Operations–Canadian GAAP[6]	180	227	138	240	220	167	242	(84)
US GAAP Adjustments	(20)	(14)	39	(89)	(12)	(1)	(12)	16
Net Income (Loss) from Continuing Operations–US GAAP	160	213	177	151	208	166	230	(68)
Net Income (Loss) as Previously Reported–Canadian GAAP	192	251	143	263	220	181	246	(56)
Changes in Accounting Policies	(8)	(11)	-	(10)	-	(10)	-	(30)
Net Income (Loss)–Canadian GAAP	184	240	143	253	220	171	246	(86)
US GAAP Adjustments	(20)	(51)	39	(89)	(12)	(34)	(12)	16
Net Income (Loss)–US GAAP	**164**	**189**	**182**	**164**	**208**	**137**	**234**	**(70)**
Earnings per Common Share from Continuing Operations ($/share)								
Canadian GAAP–Basic	1.41	1.84	1.07	1.95	1.70	1.35	1.87	(0.67)
Canadian GAAP–Diluted	1.39	1.83	1.06	1.94	1.69	1.33	1.85	(0.66)
US GAAP–Basic	1.26	1.73	1.37	1.23	1.61	1.34	1.78	(0.54)
US GAAP–Diluted	1.24	1.72	1.35	1.22	1.60	1.32	1.76	(0.53)
Earnings per Common Share ($/share)								
Canadian GAAP–Basic	1.44	1.95	1.11	2.05	1.70	1.38	1.90	(0.69)
Canadian GAAP–Diluted	1.42	1.94	1.09	2.04	1.69	1.36	1.88	(0.68)
US GAAP–Basic	1.29	1.54	1.41	1.33	1.61	1.11	1.81	(0.56)
US GAAP–Diluted	1.27	1.53	1.39	1.32	1.60	1.09	1.79	(0.55)
Dividends Declared[7]	0.10	0.075	0.10	0.075	0.10	0.075	0.10	0.10
Common Share Prices ($/share)								
Toronto Stock Exchange–High	53.35	34.85	56.50	35.59	53.70	39.68	58.66	47.08
Toronto Stock Exchange–Low	45.00	29.30	46.80	28.26	44.34	33.02	48.17	36.65
New York Stock Exchange–High (US$)	40.61	22.55	42.29	26.31	42.13	29.00	46.56	36.47
New York Stock Exchange–Low (US$)	34.10	19.89	34.49	19.75	33.88	24.03	39.20	27.32

Notes:

1 Excludes results of our Buffalo field, offshore Australia where we concluded production and the previously reported sale of non-core conventional light oil assets in southeast Saskatchewan. These results are shown as discontinued operations (see Note 11 to the Consolidated Financial Statements).

2 Includes impairment charge of $269 million (see Note 5 to the Consolidated Financial Statements).

3 Plant turnarounds and coker maintenance at Syncrude in the fourth quarters of 2003 and 2004 increased operating costs and temporarily reduced production volumes.

4 In 2004, a gain of $24 million was recorded on the sale of minor oil and gas assets by our Canadian oil and gas business.

5 Includes the impact of changes in accounting policies as described in Note 1(r) to the Consolidated Financial Statements.

6 Canadian GAAP net income includes a reduction in tax rates for Canadian resource activities in the second quarter of 2003. This reduction was recognized in the fourth quarter of 2003 for US GAAP.

7 In February 2005, the Board of Directors declared a regular quarterly dividend of $0.10 per common share, payable April 1, 2005, to shareholders of record on March 10, 2005.

8 At December 31, 2004, there were 1,329 registered holders of common shares and 129,199,583 common shares outstanding.

OIL AND GAS PRODUCING ACTIVITIES AND SYNCRUDE OPERATIONS (UNAUDITED)

The following oil and gas information is provided in accordance with the US Financial Accounting Standards Board Statement No. 69 *Disclosures about Oil and Gas Producing Activities*. It also includes information relating to our interest in Syncrude as it produces a crude oil product similar to our oil and gas activities even though these operations are considered mining activities under SEC regulations.

A. Reserve Quantity Information

Our net proved reserves and changes in those reserves for our conventional operations (excluding Syncrude) are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year and at least 80% of the reserves (including Syncrude) have been assessed by independent qualified reserves consultants.

Estimates of conventional crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year-end. See *Critical Accounting Estimates* in Item 7 for a description of our reserves estimation process.

Conventional oil and bitumen are in mmbbls and natural gas in bcf	Total Conventional Oil	Total Conventional Gas	Yemen[1] Oil	Canada Oil	Canada Gas	Canada Bitumen[2]	United States Oil	United States Gas	United Kingdom Oil	United Kingdom Gas	Other Countries[3] Oil
Proved Developed and Undeveloped Reserves[4]											
December 31, 2001	309	791	111	157	546	-	28	245	-	-	13
Extensions and Discoveries	72	103	23	9	31	1	32	72	-	-	7
Purchases of Reserves in Place	-	1	-	-	1	-	-	-	-	-	-
Sales of Reserves in Place	(6)	(1)	-	(2)	(1)	-	-	-	-	-	(4)
Revisions of Previous Estimates	(6)	(10)	(14)	7	(6)	-	1	(4)	-	-	-
Production	(45)	(81)	(20)	(16)	(47)	-	(3)	(34)	-	-	(6)
December 31, 2002	**324**	**803**	**100**	**155**	**524**	**1**	**58**	**279**	**-**	**-**	**10**
Extensions and Discoveries	48	33	36	10	20	-	1	13	-	-	1
Purchases of Reserves in Place	19	21	-	-	-	-	19	21	-	-	-
Sales of Reserves in Place	(24)	(7)	-	(24)	(6)	-	-	(1)	-	-	-
Revisions of Previous Estimates	(31)	(99)	(5)	(31)	(88)	3	(2)	(11)	-	-	4
Production	(47)	(90)	(21)	(13)	(45)	-	(9)	(45)	-	-	(4)
December 31, 2003	**289**	**661**	**110**	**97**	**405**	**4**	**67**	**256**	**-**	**-**	**11**
Extensions and Discoveries	244	33	1	3	18	239	1	15	-	-	-
Purchases of Reserves in Place	127	23	-	1	-	-	-	-	126	23	-
Sales of Reserves in Place	(1)	(3)	-	(1)	(2)	-	-	(1)	-	-	-
Revisions of Previous Estimates	(265)	(25)	(12)	(11)	(7)	(243)	(6)	(9)	3	(9)	4
Production	(43)	(89)	(19)	(10)	(42)	-	(10)	(46)	(1)	(1)	(3)
December 31, 2004	**351**	**600**	**80**	**79**	**372**	**-**	**52**	**215**	**128**	**13**	**12**
Proved Developed Reserves[5]											
December 31, 2002	**246**	**702**	**61**	**130**	**487**	**1**	**46**	**215**	**-**	**-**	**8**
December 31, 2003	**216**	**576**	**63**	**87**	**367**	**4**	**54**	**209**	**-**	**-**	**8**
December 31, 2004	**199**	**518**	**49**	**72**	**348**	**-**	**48**	**166**	**20**	**4**	**10**

Notes:

1 Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners' share ranging from 20% to 33%. The Government's share of profit oil represents their royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves have been determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) since the barrels necessary to achieve cost recovery change with prevailing oil prices.

2 Represents bitumen reserves from the insitu recovery of Canadian oil sands, rather than upgraded synthetic crude oil reserves.

3 Represents reserves in Australia, Nigeria and Colombia.

4 "Proved" oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation test.

5 "Proved developed" oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

Our net proved reserves and changes in those reserves for our Syncrude operations are disclosed below. Additional disclosures required by SEC Industry Guide 7 can be found on pages 19 and 20. The net proved reserves represent management's best estimate of proved synthetic reserves after royalties. Reserve estimates are prepared internally each year and at least 80% of our reserves (including oil and gas activities) have been assessed by independent qualified reserves consultants.

Estimates of Syncrude's synthetic crude oil reserves are based on detailed geological and engineering assessments of the bitumen volume in-place, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity, and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling. In accordance with the approved mining plan, there are an estimated 2,175 million tons of economically extractable oil sands in the Base and North Mines, with an average bitumen grade of 10.6 weight percent. The Aurora North Mine contains an estimated 4,720 million tons of economically extractable oil sands at an average bitumen grade of 11.2 weight percent. Aurora South Lease 31 contains measured economically extractable oil sands of 3,440 million tons at an average bitumen grade of 10.8 weight percent.

	Synthetic Crude Oil		
(millions of barrels)	Base Mine and North Mine[1]	Aurora[2]	Total
December 31, 2001	**65**	**166**	**231**
Revision of Previous Estimates	(2)	(10)	(12)
Extensions and Discoveries	-	13	13
Production	(5)	(1)	(6)
December 31, 2002	**58**	**168**	**226**
Revision of Previous Estimates	1	4	5
Extensions and Discoveries	-	22	22
Production	(4)	(1)	(5)
December 31, 2003	**55**	**193**	**248**
Revision of Previous Estimates	(1)	(5)	(6)
Extensions and Discoveries	-	19	19
Production	(4)	(2)	(6)
December 31, 2004	**50**	**205**	**255**

Notes:
1 Leases 12 and 17
2 Leases 10, 12, 31 and 34.

B. Capitalized Costs (excluding Syncrude operations)

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated Depreciation, Depletion, Amortization and Impairment	Capitalized Costs
December 31, 2004				
Yemen	2,022	16	1,550	488
Canada	3,732	136	2,025	1,843
United States	2,102	147	1,037	1,212
United Kingdom	3,117	382	16	3,483
Other Countries	437	98	408	127
Total Capitalized Costs	**11,410**	**779**	**5,036**	**7,153**
December 31, 2003				
Yemen	1,881	17	1,497	401
Canada	3,271	129	1,863	1,537
United States	2,034	123	892	1,265
Other Countries	454	85	420	119
Total Capitalized Costs	**7,640**	**354**	**4,672**	**3,322**
December 31, 2002				
Yemen	2,024	30	1,646	408
Canada	2,882	216	1,137	1,961
United States	2,061	125	959	1,227
Other Countries	460	54	382	132
Total Capitalized Costs	**7,427**	**425**	**4,124**	**3,728**

C. Costs Incurred (excluding Syncrude operations)

(Cdn$ millions)	Total Conventional Oil and Gas	Conventional Oil and Gas				
		Yemen	Canada	United States	United Kingdom	Other Countries
Year Ended December 31, 2004						
Property Acquisition Costs						
Proved	1,774	-	4	-	1,770	-
Unproved	1,491	-	-	-	1,491	-
Exploration Costs	339	22	56	162	4	95
Development Costs	1,102	267	491	267	53	24
Asset Retirement Costs	168	3	27	4	134	-
Total Costs Incurred	**4,874**	**292**	**578**	**433**	**3,452**	**119**
Year Ended December 31, 2003						
Property Acquisition Costs						
Proved	164	-	-	164	-	-
Unproved	38	-	-	38	-	-
Exploration Costs	291	34	51	109	-	97
Development Costs	752	219	259	249	-	25
Asset Retirement Costs	185	-	69	62	-	54
Total Costs Incurred	**1,430**	**253**	**379**	**622**	**-**	**176**
Year Ended December 31, 2002						
Property Acquisition Costs						
Proved	4	-	4	-	-	-
Unproved	31	-	-	31	-	-
Exploration Costs	228	22	60	85	-	61
Development Costs	1,077	209	258	541	-	69
Total Costs Incurred	**1,340**	**231**	**322**	**657**	**-**	**130**

D. Results of Operations for Producing Activities (excluding Syncrude operations)

(Cdn$ millions)	Total Conventional Oil and Gas	Conventional Oil and Gas: Yemen	Canada	United States	United Kingdom	Other Countries
Year Ended December 31, 2004						
Net Sales	2,538	921	622	811	36	148
Production Costs	437	109	156	106	6	60
Exploration Expense	246	2	21	138	3	82
Depreciation, Depletion, Amortization and Impairment	712	169	240	258	18	27
Other Expenses (Income)	106	4	38	19	-	45
	1,037	637	167	290	9	(66)
Income Tax Provision (Recovery)	406	222	75	104	4	1
Results of Operations	**631**	**415**	**92**	**186**	**5**	**(67)**
Year Ended December 31, 2003						
Net Sales	2,338	827	675	707	-	129
Production Costs	382	92	159	86	-	45
Exploration Expense	201	17	35	89	-	60
Depreciation, Depletion, Amortization and Impairment	945	168	510	207	-	60
Other Expenses (Income)	49	4	26	(1)	-	20
	761	546	(55)	326	-	(56)
Income Tax Provision (Recovery)	221	191	(82)	115	-	(3)
Results of Operations	**540**	**355**	**27**	**211**	**-**	**(53)**
Year Ended December 31, 2002						
Net Sales	1,984	789	656	296	-	243
Production Costs	428	86	176	94	-	72
Exploration Expense	189	21	38	82	-	48
Depreciation, Depletion, Amortization and Impairment	634	149	253	133	-	99
Other Expenses (Income)	79	4	41	14	-	20
	654	529	148	(27)	-	4
Income Tax Provision (Recovery)	238	188	59	(10)	-	1
Results of Operations	**416**	**341**	**89**	**(17)**	**-**	**3**

E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein (excluding Syncrude operations)

The following disclosure is based on estimates of net proved reserves (excluding Syncrude) and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved conventional oil and gas reserves. Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory-tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

(Cdn$ millions)	Total	Yemen	Canada	United States	United Kingdom	Other Countries
December 31, 2004						
Future Cash Inflows	18,950	3,779	4,747	4,085	5,852	487
Future Production Costs	4,781	722	2,135	613	1,271	40
Future Development Costs	1,477	275	100	185	903	14
Future Dismantlement and Site Restoration Costs, Net	626	4	149	129	336	8
Future Income Tax	2,798	388	382	845	1,058	125
Future Net Cash Flows	9,268	2,390	1,981	2,313	2,284	300
10% Discount Factor	2,978	499	760	631	1,011	77
Standardized Measure	**6,290**	**1,891**	**1,221**	**1,682**	**1,273**	**223**
December 31, 2003						
Future Cash Inflows	14,660	4,416	5,319	4,470	-	455
Future Production Costs	3,651	868	1,980	666	-	137
Future Development Costs	788	412	102	249	-	25
Future Dismantlement and Site Restoration Costs, Net	309	-	112	137	-	60
Future Income Tax	2,152	574	656	854	-	68
Future Net Cash Flows	7,760	2,562	2,469	2,564	-	165
10% Discount Factor	2,243	620	879	691	-	53
Standardized Measure	**5,517**	**1,942**	**1,590**	**1,873**	-	**112**
December 31, 2002						
Future Cash Inflows	18,687	4,662	9,067	4,516	-	442
Future Production Costs	3,943	881	2,375	535	-	152
Future Development Costs	722	296	169	228	-	29
Future Dismantlement and Site Restoration Costs, Net	227	-	24	150	-	53
Future Income Tax	3,650	790	1,976	863	-	21
Future Net Cash Flows	10,145	2,695	4,523	2,740	-	187
10% Discount Factor	3,776	819	2,081	818	-	58
Standardized Measure	**6,369**	**1,876**	**2,442**	**1,922**	-	**129**

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	2004	2003	2002
Beginning of Year	5,517	6,369	3,087
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(1,674)	(2,298)	(1,158)
Net Changes in Prices and Production Costs Related to Future Production	142	(1,249)	3,083
Extensions, Discoveries and Improved Recovery, Less Related Costs[1]	(71)	740	1,929
Changes in Estimated Future Development and Dismantlement Costs	(122)	(279)	(103)
Previous Estimated Future Development and Dismantlement Costs Incurred during the Period	604	456	425
Revisions of Previous Quantity Estimates	(223)	(291)	267
Accretion of Discount	692	884	409
Purchases of Reserves in Place	1,764	354	2
Sales of Reserves in Place	(20)	(252)	(109)
Net Change in Income Taxes	(319)	1,083	(1,463)
End of Year	**6,290**	**5,517**	**6,369**

Notes:
1 Includes approximately $230 million of negative deemed discounted future net cash flows relating to bitumen reserves based on 2004 year-end assumptions.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

There were no disagreements with accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15-d-15(e)) as of the end of the period covered by this report. They concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were adequate and effective in ensuring that material information relating to the Company and its consolidated subsidiaries would be made known to them by others within those entities, particularly during the period in which this report was being prepared. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and in reaching a reasonable level of assurance, management necessarily is required to apply its judgement in evaluating the cost-benefit relationship of possible controls and procedures.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2004. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

There were two important exclusions from our assessment.

- Our 7.23% working interest in the Syncrude joint venture was excluded from our assessment since we do not have the ability to dictate or modify this entity's internal control over financial reporting and we do not have the practical ability to assess those controls. Our 7.23% working interest in the Syncrude joint venture represents 7.4% of our consolidated total assets and 8.2% of our consolidated revenues as at and for the year ended December 31, 2004. Despite this exclusion, we have assessed our internal control over financial reporting with respect to the inclusion of our share of this joint venture and its results for the year in our consolidated financial statements.
- The internal control over financial reporting of Nexen Petroleum UK Limited, formerly EnCana (UK) Limited, has been excluded from our assessment. Our acquisition of EnCana (UK) Limited closed on December 1, 2004 and we were unable to formally document and assess the internal controls over financial reporting within this acquired company by the end of 2004. Nexen Petroleum UK Limited represents 35.9% of our consolidated total assets and 0.9% of our consolidated revenues as at and for the year ended December 31, 2004. The significance of this acquisition to our consolidated financial statements is described in Note 2 to our consolidated financial statements. Despite this exclusion, we have assessed our internal controls with respect to the acquisition process and our internal controls relating to the consolidation and disclosure of the acquired company and its results since December 1, 2004 in our consolidated financial statements.

Further financial information with respect to the Syncrude joint venture and Nexen Petroleum UK Limited may be found in the Syncrude and North Sea segments of Note 18 to our consolidated financial statements.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by Deloitte and Touche LLP, independent registered Chartered Accountants, as stated in their report which is set out on page 120 of this Form 10-K.

CHANGES IN INTERNAL CONTROLS

We have continually had in place systems relating to internal control over financial reporting. There has not been any change in our internal control over financial reporting during the fourth quarter of 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. During 2004, we continued to improve and enhance our financial reporting systems by continuing to implement our existing Systems, Applications, and Products in Data Processing (SAP) system into our North American chemicals operations. We expect that the system conversion of our Brazil chemicals operations will be completed in the first half of 2005. We also implemented SAP in our Nigerian oil and gas operations during the year. The conversion of data and the implementation and operation of SAP has been continually monitored and reviewed.

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited management's assessment, included in the foregoing Management's Report on Internal Control over Financial Reporting that Nexen Inc. (the "Company") maintained effective internal control over financial reporting as at December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As described in Management's Report on Internal Control over Financial Reporting, management excluded from their assessment, firstly, the internal control over financial reporting at the Syncrude joint venture whose financial statements reflect total assets and revenues constituting 7.4% and 8.2%, respectively, of the related consolidated financial statement amounts as at and for the year ended December 31, 2004 and, secondly, the internal control over financial reporting at Nexen Petroleum UK Limited (formerly EnCana (UK) Limited) which was acquired on December 1, 2004 and whose financial statements reflect total assets and revenues constituting 35.9% and 0.9%, respectively, of the related consolidated financial statement amounts as at and for the year ended December 31, 2004. Accordingly, our audit did not include the internal control over financial reporting at either the Syncrude joint venture or Nexen Petroleum UK Limited. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections or any evaluation of effectiveness of the internal control over financial reporting to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as at December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of Nexen Inc. as at and for the year ended December 31, 2004 and our report dated February 7, 2005 expressed an unqualified opinion on those financial statements and included a separate report on Canada-United States of America reporting differences.

Calgary, Canada
February 7, 2005

(signed) "Deloitte & Touche LLP"
Independent Registered
Chartered Accountants

corporate governance

Long Lake, Alberta, Canada

Items 10 to 15

contents

Item 10. Directors and Executive Officers of the Registrant

DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. On January 5, 2004, the Board determined that, until changed, there will be 11 directors.

Our By-Laws provide that directors will be elected at the annual general meeting of shareholders (AGM) each year and will hold office until their successors are elected. All of our current directors were elected at the last AGM.

This table shows each director's principal occupation or employment during the past five years and any other directorships they held in public companies as at February 10, 2005. The following directors are management nominees for election to the Board.

Name (Age)	**Principal Occupation and Other Directorships**	**Director Since**
Charles W. Fischer (54)	President and Chief Executive Officer (CEO) of Nexen. Formerly, Executive Vice President and Chief Operating Officer (COO).	2000
Dennis G. Flanagan[1, 2] (65)	Retired oil executive. Director of NAL Oil & Gas Trust.	2000
David A. Hentschel[1] (71)	Oil and gas consultant. Retired oil executive. Formerly, Chairman and CEO of Occidental Oil and Gas Corporation. A director of Cimarex Energy Co.	1985
S. Barry Jackson[1] (52)	Retired oil executive. Formerly, President and CEO of Crestar Energy Inc. Chairman of Resolute Energy Inc. and Deer Creek Energy Limited. A director of TransCanada Corporation and TransCanada Pipelines Limited.	2001
Kevin J. Jenkins[1, 2] (48)	Managing Director of TriWest Capital Management Corp. Formerly, President and CEO and a director of The Westaim Corporation.	1996
Eric P. Newell, O.C. (60)	Retired Chairman and CEO of Syncrude Canada Ltd. Director of Canfor Corporation and Terasen Inc.	2004
Thomas C. O'Neill[1, 2] (59)	Retired Chairman of PwC Consulting. Formerly, CEO of PwC Consulting. Prior to that, COO of PricewaterhouseCoopers LLP, Global. Prior to that, CEO of PricewaterhouseCoopers LLP, Canada. Director of BCE Inc., Loblaw Companies Limited, Dofasco Inc. and Adecco S.A.	2002
Francis M. Saville, Q.C. (66)	Counsel to Fraser Milner Casgrain LLP, Barristers and Solicitors. Formerly, Senior Partner and Vice Chair of Fraser Milner Casgrain LLP, Barristers and Solicitors. Director of Mullen Transportation Inc.	1994
Richard M. Thomson, O.C.[1, 2] (71)	Retired banking executive. Chair of the Board of Nexen and a director of The Thomson Corporation and Trizec Properties Inc.	1997
John M. Willson (65)	Retired President and CEO of Placer Dome Inc. Director of Aber Diamond Corporation, Finning International Inc. and PanAmerican Silver Corporation.	1996
Victor J. Zaleschuk (61)	Retired President and CEO of Nexen. Chairman of Cameco Corporation and a director of Agrium Inc.	1997

Notes:

1 Members of Nexen's Audit and Conduct Review Committee. All members of the Committee are independent pursuant to Nexen's Categorical Standards for Director Independence which meet or exceed all applicable regulations.

2 Financial Experts on Nexen's Audit and Conduct Review Committee.

INDEPENDENCE AND BOARD COMMITTEES

Director's independence was affirmatively determined by the Board in reference to our current Categorical Standards for Director Independence (Categorical Standards) which were adopted on February 10, 2005. Our Categorical Standards meet or exceed the requirements set out in US Securities and Exchange Commission (SEC) rules and regulations, the *Sarbanes-Oxley Act of 2002* (Sarbanes-Oxley), the New York Stock Exchange (NYSE) rules, proposed *National Instrument 58-201 Corporate Governance Guidelines* and applicable provisions of *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities*.

	Committees (Number of Members)					
	Audit and Conduct Review[1, 2] (6)	**Compensation and Human Resources**[1] (6)	**Corporate Governance and Nominating**[1] (6)	**Finance** (7)	**Reserves Review**[3] (7)	**Safety, Environment and Social Responsibility** (7)
Independent Outside Directors						
Dennis G. Flanagan[4]	✓		✓	✓	Chair	
David A. Hentschel[4]	Chair	✓			✓	✓
S. Barry Jackson	✓	✓			✓	Chair
Kevin J. Jenkins[4]	✓		✓	Chair		✓
Thomas C. O'Neill[4]	✓		✓		✓	✓
Francis M. Saville, Q.C.[5]		✓	Chair	✓		✓
Richard M. Thomson, O.C.[4,6]	✓	✓	✓	✓		
John M. Willson		Chair		✓	✓	✓
Victor J. Zaleschuk		✓	✓	✓	✓	
Outside Director—Not Independent						
Eric P. Newell, O.C.[7]				✓	✓	✓
Management Director—Not Independent						
Charles W. Fischer[8]						

Notes:

1 All members of the Audit and Conduct Review Committee, Corporate Governance and Nominating Committee, and Compensation and Human Resources Committee are independent. All members of the Audit and Conduct Review Committee are independent under additional regulatory requirements for audit committee members.

2 The Board has considered the circumstances of Mr. O'Neill's service on four audit committees, plus Nexen's. Mr. O'Neill is retired and holds neither a full nor part-time employee position. His only commitments are to the boards and committees on which he serves. Accordingly, the Board has determined that service as an audit committee member on four other public companies does not impair Mr. O'Neill's ability to serve on Nexen's Audit and Conduct Review Committee.

3 A majority of the Reserves Review Committee members are independent.

4 A financial expert under US regulatory requirements.

5 Mr. Saville retired as a Partner and Vice Chair of Fraser Milner Casgrain (FMC) in January of 2004. Since February 1, 2004, he has been Counsel to the firm. Mr. Saville does not solicit or participate in any work done by FMC for Nexen and, as Counsel with FMC, does not receive any share of the fees paid to FMC by Nexen.

6 Mr. Thomson, Chair of the Board, presides at the regularly scheduled in camera sessions of the non-management directors.

7 Mr. Newell is not independent because a Nexen officer sits on the compensation committee of Syncrude. If circumstances remain the same, Mr. Newell will be independent after January 2, 2007 (three years after his retirement from Syncrude).

8 Mr. Fischer is not independent as he is the President and CEO of Nexen.

COMMUNICATING WITH THE BOARD

Shareholders may write to the Board or any member or members of the Board in care of the following address:

By mail to: Nexen Inc.
801 – 7th Avenue S.W., Calgary, Alberta, T2P 3P7

Attention: John B. McWilliams
Senior Vice President, General Counsel and Secretary

By email to: board@nexeninc.com

Nexen receives an exceptional number of inquiries on a large range of subjects every day. As a result, the Board is not able to respond to all shareholder inquiries directly and has consulted with management to develop a process to assist in managing inquiries directed to the Board or its members.

Letters and emails addressed to the Board, any of its members or the independent directors, as a group, are reviewed to determine if a response from the Board is appropriate. While the Board oversees management, it does not participate in the day-to-day functions and operations of Nexen and is not normally in the best position to respond to inquiries on those matters. Inquiries on operations or day-to-day management of Nexen will be directed to the appropriate personnel within Nexen for a response. The Board has instructed the Secretary to review all correspondence and, in his discretion, not forward items if they:

- are not relevant to Nexen's operations, policies and philosophies;
- are commercial in nature; or
- are not appropriate for consideration by the Board.

All inquiries will receive a written response from either the Board or management, as appropriate. The Secretary maintains a log of all correspondence addressed to members of the Board. Directors may review the log at any time and request copies of any correspondence received.

EXECUTIVE OFFICERS

The Board determines the term of office for each executive officer. Below are Nexen's officers. Prior offices and non-executive positions are set out for officers who have not held their current executive positions with Nexen for more than five years. Start dates are indicated for officer positions with Nexen.

Officer (Age)	Current and Past Position(s) with Nexen	Effective Date of Current Position	Executive Officer Since
Charles W. Fischer (54)	President and CEO and a director Formerly: Executive Vice President and COO since May 14, 1997	June 1, 2001	1994
Marvin F. Romanow (49)	Executive Vice President and CFO Formerly: Senior Vice President, Finance and CFO since February 19, 1999 Vice President, Finance and CFO since February 27, 1998	June 1, 2001	1997
Laurence Murphy[1] (54)	Senior Vice President, International Oil and Gas	January 1, 1999	1998
John B. McWilliams, Q.C.[1] (57)	Senior Vice President, General Counsel and Secretary	May 11, 1993	1987
Douglas B. Otten[1] (61)	Senior Vice President, United States Oil and Gas	May 12, 1998	1990
Thomas A. Sugalski[1] (61)	Senior Vice President, Chemicals	May 10, 1994	1988
Roger D. Thomas[1] (52)	Senior Vice President, Canadian Oil and Gas	February 19, 1999	1998
Nancy F. Foster (45)	Vice President, Human Resources and Corporate Services Formerly: Division Vice President, Finance–Canadian Oil and Gas since February 1, 1999 General Manager, Human Resources since March 1, 1998	July 11, 2000	2000
Gary H. Nieuwenburg (46)	Vice President, Synthetic Crude Formerly: Vice President, Corporate Planning and Business Development since February 16, 2001 Division Vice President, Exploration and Production–Canadian Oil and Gas since October 1, 1998	July 11, 2002	2001
Kevin J. Reinhart (46)	Vice President, Corporate Planning and Business Development Formerly: Treasurer since October 20, 1998	July 11, 2002	1994
Una M. Power[2] (40)	Treasurer Formerly: Controller and Director, Corporate Insurance since May 2, 2002 Controller and Director, Risk Management since December 1, 1998	July 11, 2002	1998
Michael J. Harris (41)	Controller Formerly: Manager, Corporate Finance–Treasury since December 1, 2000 General Manager–New Ventures Finance since March 1, 2000 Division Vice President, Finance–International since March 1, 1999	December 10, 2002	2002

Notes:
1 Officer has held the same executive position with Nexen for more than 5 years.
2 Ms. Power concurrently maintained her position as Controller until December 10, 2002.

Ethics Policy

Under Nexen's Ethics Policy, all directors, officers and employees must demonstrate a commitment to ethical business practices and behaviour in all business relationships, both within and outside of Nexen. An employee is not permitted to commit an unethical, dishonest or illegal act or to instruct other employees to do so. Our Ethics Policy has been adopted as a code of ethics applicable to our principal executive officer, principal financial officer and principal accounting officer or controller.

Any waivers of or changes to the Ethics Policy must be approved by the Board of Directors and appropriately disclosed. There were no waivers of the Ethics Policy during 2004. Revisions were made to our Ethics Policy to provide for an external Integrity Hotline which came into effect on February 1, 2005.

Our Ethics Policy is available on our internet website at www.nexeninc.com and it is our intention to provide disclosure regarding waivers of or changes to our Ethics Policy in this manner. In addition, our Ethics Policy is filed on SEDAR and all future amendments to the Ethics Policy will be filed on SEDAR. A hard copy of the Ethics Policy can be requested from the Assistant Corporate Secretary by telephone at (403) 699-4000, by facsimile at (403) 716-0468 or by email at assistant_secretary@nexeninc.com.

Corporate Governance

Nexen's Board of Directors takes their duties and responsibilities for good corporate governance seriously. Nexen supports and conducts business according to the rules and guidelines of the Toronto Stock Exchange (TSX), NYSE and proposed *National Policy 58-201 Corporate Governance Guidelines*. Nexen's corporate governance practices comply with the corporate governance practices followed by domestic companies under NYSE listing standards.

On March 1, 2005, our CEO certified to the NYSE that he was unaware of any violation by Nexen of the NYSE's corporate governance listing standards. Nexen also provided the required Annual Written Affirmation to the NYSE on March 1, 2005. As well, our CEO and CFO have certified the quality of Nexen's public disclosure to the SEC.

Our Committee Mandates, including the Mandates for each of the Audit and Conduct Review Committee, the Compensation and Human Resources Committee and the Corporate Governance and Nominating Committee and our Corporate Governance Policy and Categorical Standards are available on our website at www.nexeninc.com and it is our intention to provide disclosure in this manner. Shareholders wishing to receive a copy of any of these documents may contact the Assistant Corporate Secretary by telephone at (403) 699-4000, by facsimile at (403) 716-0468 or by email at assistant_secretary@nexeninc.com.

Item 11. Executive Compensation

SUMMARY COMPENSATION

Name and Principal Position	Year	Annual Compensation: Salary	Bonus[1]	Other Annual Compensation	Long-Term Compensation Awards: Securities Underlying Options Granted	Restricted Shares or Restricted Share Units	All Other Compensation
		($)	($)	($)	(#)	($)	($)
Charles W. Fischer	2004	847,917	1,310,000	-	150,000	-	50,875[2]
President and CEO	2003	725,000	600,000	-	100,000	-	43,500[2]
	2002	637,500	300,000	-	100,000	-	38,250[2]
Marvin F. Romanow	2004	462,500	555,000	-	57,000	-	27,750[2]
Executive Vice President	2003	440,500	267,000	-	55,000	-	26,430[2]
and CFO	2002	418,000	310,000	-	50,000	-	25,080[2]
Douglas B. Otten	2004	438,005	299,345	-	40,000	-	26,280[2] / 63,536[3]
Senior Vice President,	2003	416,152	226,170	-	37,000	-	24,969[2] / 60,221[3]
United States Oil and Gas	2002	485,873	125,886	-	35,000	-	29,156[2] / 63,004[3]
Thomas A. Sugalski	2004	403,465	208,240	-	30,000	-	24,208[2] / 56,165[4]
Senior Vice President,	2003	384,439	156,830	-	30,000	-	23,066[2] / 53,395[4]
Chemicals	2002	449,993	118,019	-	30,000	-	26,999[2] / 60,889[4]
Laurence Murphy	2004	385,500	565,000	-	40,000	-	23,130[2]
Senior Vice President,	2003	366,500	196,000	-	37,000	-	21,990[2]
International Oil and Gas	2002	346,000	90,000	-	35,000	-	20,760[2]

Notes:
For the CEO and four other highest compensated officers (all numbers stated in Cdn$).

1 Bonuses for a year are determined based on performance during the year and are paid to the employee in the following year. Bonuses are paid pursuant to the Incentive Compensation Plan. The bonuses indicated were the payments made in the year shown and include special bonuses of $450,000, $225,000 and $200,000 paid to Messrs. Fischer, Murphy and Romanow, respectively, for successful completion of the North Sea Acquisition in 2004.
2 Contributions to the Employee Savings Plan.
3 Nexen contributed to a Qualified Defined Contribution Plan and a Restoration Plan with Nexen Petroleum USA Inc. for Mr. Otten.
4 Nexen contributed to a Qualified Defined Contribution Plan and a Restoration Plan with Nexen Chemicals USA Inc. for Mr. Sugalski.

Options

Pursuant to Nexen's Tandem Option (TOP) Plan, the Board, on the recommendation of the Compensation and Human Resources Committee, may grant options to Nexen officers and employees. Nexen does not receive any consideration when options are granted. The exercise price is the market price of Nexen's common shares on the TSX for Canadian based employees or the NYSE for US-based employees, when the option is granted.

The Board determines the term of each option, to a maximum of ten years, and the vesting schedule. For all options granted before February 2001, each option has a term of ten years; 20% of the grant vests after six months and then 20% more vests each year for four years on the anniversary of the grant. In February 2001, the Compensation and Human Resources Committee and the Board approved an amendment to TOP Plan which sets out that each option granted has a term of five years and the options vest one-third each year over three years. Generally, if a change of control event occurs (as defined in the TOP Plan), all issued but unvested options will become vested.

OPTION GRANTS DURING 2004

Name	Securities Underlying Options Granted	% of Total Options/Stock Appreciation Rights Granted to Employees in Financial Year	Exercise or Base Price[1]	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term 5%	10%
	(#)		($/Security)[2]		($)	($)
Charles W. Fischer	150,000	4.5	50.87	December 6, 2009	2,108,166	4,658,497
Marvin F. Romanow	57,000	1.7	50.87	December 6, 2009	801,103	1,770,229
Douglas B. Otten	40,000	1.2	42.32 (US$)	December 6, 2009	604,442	1,335,658
Thomas A. Sugalski	30,000	0.9	42.32 (US$)	December 6, 2009	453,331	1,001,744
Laurence Murphy	40,000	1.2	50.87	December 6, 2009	562,178	1,242,266

Notes:
1 Equal to the market value of securities underlying options on the date of grant.
2 All values in Canadian dollars unless otherwise noted.

OPTIONS EXERCISED DURING 2004 AND FINANCIAL YEAR-END OPTION VALUES

Name	Securities Acquired on Exercise	Value Realized[1]	Number of Securities Underlying Unexercised Options at Financial Year-end Exercisable / Unexercisable	Value of Unexercised In-The-Money-Options at Financial Year-end Exercisable / Unexercisable
	(#)	($)[2]	(#)	($)[2]
Charles W. Fisher	26,400	731,328	514,000 / 249,000	9,562,740 / 830,610
Marvin F. Romanow	62,000	968,300	202,200 / 109,800	3,068,535 / 432,465
Douglas B. Otten	75,696	1,979,928	111,805 / 75,970	1,981,117 / 513,066
Thomas A. Sugalski	95,500	2,111,164	35,800 / 59,700	827,468 / 429,066
Laurence Murphy	108,000	2,797,130	104,030 / 75,970	1,406,613 / 297,578

Notes:
1 Equals market price at the time of the exercise minus exercise price.
2 All values in Canadian dollars.

Employee Savings Plan

The Summary Compensation Table includes Nexen's contribution to the savings plan made on behalf of executive officers. All regular employees may participate in our Employee Savings Plan. Through payroll deductions, employees may contribute any percentage of their regular earnings to purchase Nexen common shares or mutual fund units or a combination of Nexen common shares and mutual fund units. Nexen matches employee contributions to a maximum of 6% of regular earnings. The extent of matching is based on the investment option selected and the employee's length of participation in the plan. The full amount of Nexen's contribution is invested in common shares and is fully vested immediately. Employee and employer contributions may be allocated to registered or non-registered accounts. Employees may vote the Nexen common shares they hold in the Employee Savings Plan.

For employees in the United States, the savings plan is intended to qualify under Section 401(a) and 501(a) of the Internal Revenue Code. Nexen matches employee contributions to a maximum of 6% of eligible compensation. The full amount of Nexen's matching contribution is invested in common shares and is fully vested immediately.

Benefit Plans

All named executive officers, except Mr. Sugalski and Mr. Otten, are members of Nexen's Defined Benefit Pension Plan and of the Executive Benefit Plan. Both Mr. Sugalski and Mr. Otten are employed in the United States and are members of a qualified 401(k) savings plan, a qualified defined contribution pension plan and a non-qualified restoration plan.

DEFINED BENEFIT PENSION PLAN (CANADA)

Under this registered pension plan, participants must contribute 3% of their regular gross earnings, up to an allowable maximum. Upon retirement, participants are entitled to receive a benefit equal to 1.7% of their average earnings for the 36 highest paid consecutive months during the ten years before retirement, multiplied by the number of years of credited service. The plan is integrated with the Canada Pension Plan (CPP) in order to provide a maximum offset of one-half of the prevailing CPP benefit. Nexen contributed $5.1 million to the Defined Benefit Pension Plan in 2004.

Pension benefits earned prior to January 1, 1993 may be indexed on an ad hoc basis. Pension benefits earned after December 31, 1992 will be indexed at an amount not greater than 5% and not less than 0% and equal to the greater of:

- 75% of the increase in the Canadian Consumer Price Index, less 1%; and
- 25% of the increase in the Canadian Consumer Price Index.

Effective January 1, 2005, the plan was amended to permit plan participants to periodically switch between the Defined Benefit Pension Plan and the Defined Contribution Pension Plan at different stages in their careers. In addition, the benefit accrual formula under the plan was increased from 1.7% to 1.8% for contributions after January 1, 2005. Plan participants have been provided with an opportunity to further increase their benefit accrual formula on a go-forward basis, from 1.8% to 2%, through additional tax effective employee contributions. Employees who chose this option are required to contribute an additional 2% of pensionable earnings to the allowable maximum.

EXECUTIVE BENEFIT PLAN (CANADA)

The Executive Benefit Plan (EBP) provides supplemental retirement benefits for defined benefit plan participants who have earned a retirement benefit in excess of the statutory limits. This supplemental benefit provides employees the opportunity to accrue a pension that is more in line with their final earnings level and also ensures competitiveness within our marketplace. Benefits are accrued under the EBP similar to the underlying registered pension formula which provides for 1.7% for credited service prior to 2005 and 1.8% or 2% for credited service from 2005. For executive officers, annual incentive payments made during the last three years of participation in the EBP are also included for benefit accrual purposes. For the annual incentives, pension benefit is accrued on the lesser of target bonus or actual bonus paid, averaged over the final three years of participation, and the associated pension benefit is payable from the EBP.

The pension expense for the EBP is determined and recognized annually. Benefits payable for the year are paid from the cash flows from Nexen's general operating revenues and are a reduction to the related pension liability. As liabilities under the EBP are not funded, a level of protection is provided to participants through a letter of credit. The letter of credit basically makes participants secured creditors up to the aggregate value of the letter of credit. This is separate from the protection of benefits in the registered plan, which is funded. The service cost of the letter of credit was $163,500 in 2004.

Ten executive officers, together with all employees who have exceeded the statutory limit with their earned retirement benefits participate in the EBP. The benefit calculation formula is the same as under the Defined Benefit Pension Plan.

As indicated in the notes to our financial statements, Nexen's supplemental pension plan's accumulated benefit obligation (the projected benefit obligation excluding future salary increases) was $23 million at December 31, 2004 and the projected benefit obligation for supplemental benefits was $34 million at that same date.

Effective January 1, 2005, the EBP was amended to provide a supplemental pension allocation for defined contribution plan participants who are affected by annual statutory contribution limits. In 2005, the supplemental allocation for eligible participants will be $18,000. No Canadian executive officer participates in the defined contribution plan.

DEFINED CONTRIBUTION PENSION PLAN (US)

Under this qualified retirement plan, Nexen provides participants with a contribution of 6% of eligible compensation up to the Social Security taxable wage base and 11.5% of eligible compensation that exceeds the Social Security taxable wage base. For 2004, the maximum amount of contributions permitted by legislation to defined contribution plans was $41,000 per participant.

NON-QUALIFIED RESTORATION PLAN (US)

This plan is intended to be an unfunded and non-qualified deferred compensation arrangement that provides deferred compensation benefits to a select group of management or highly compensated employees. The plan is established and maintained for the purpose of providing benefits in excess of applicable legislative limits.

ESTIMATED PENSION BENEFIT

This table shows the estimated annual pension an executive officer who retired on December 31, 2004 would receive, assuming that the amount in the Summary Compensation Table is the officer's final average salary. It includes benefits from both the Defined Benefit Pension Plan and the EBP and assumes a retirement age of 65. The normal form of benefit paid from this plan is joint life with 66 2/3% to the surviving spouse.

	Years of Service						
Renumeration ($)	**5**	**10**	**15**	**20**	**25**	**30**	**35**
300,000	24,802	49,604	74,406	99,209	124,011	148,813	173,615
350,000	29,052	58,104	87,156	116,209	145,261	174,313	203,365
400,000	33,302	66,604	99,906	133,209	166,511	199,813	233,115
450,000	37,552	75,104	112,656	150,209	187,761	225,313	262,865
500,000	41,802	83,604	125,406	167,209	209,011	250,813	292,615
550,000	46,052	92,104	138,156	184,209	230,261	276,313	322,365
600,000	50,302	100,604	150,906	201,209	251,511	301,813	352,115
650,000	54,552	109,104	163,656	218,209	272,761	327,313	381,865
700,000	58,802	117,604	176,406	235,209	294,011	352,813	411,615
750,000	63,052	126,104	189,156	252,209	315,261	378,313	441,365
800,000	67,302	134,604	201,906	269,209	336,511	403,813	471,115
850,000	71,552	143,104	214,656	286,209	357,761	429,313	500,865
900,000	75,802	151,604	227,406	303,209	379,011	454,813	530,615
950,000	80,052	160,104	240,156	320,209	400,261	480,313	560,365
1,000,000	84,302	168,604	252,906	337,209	421,511	505,813	590,115
1,050,000	88,552	177,104	265,656	354,209	442,761	531,313	619,865
1,100,000	92,802	185,604	278,406	371,209	464,011	556,813	649,615
1,150,000	97,052	194,104	291,156	388,209	485,261	582,313	679,365
1,200,000	101,302	202,604	303,906	405,209	506,511	607,813	709,115
1,250,000	105,552	211,104	316,656	422,209	527,761	633,313	738,865
1,300,000	109,802	219,604	329,406	439,209	549,011	658,813	768,615
1,350,000	114,052	228,104	342,156	456,209	570,261	684,313	798,365
1,400,000	118,302	236,604	354,906	473,209	591,511	709,813	828,115
1,450,000	122,552	245,104	367,656	490,209	612,761	735,313	857,865
1,500,000	126,802	253,604	380,406	507,209	634,011	760,813	887,615
1,550,000	131,052	262,104	393,156	524,209	655,261	786,313	917,365
1,600,000	135,302	270,604	405,906	541,209	676,511	811,813	947,115
1,650,000	139,552	279,104	418,656	558,209	697,761	837,313	976,865
1,700,000	143,802	287,604	431,406	575,209	719,011	862,813	1,006,615
1,750,000	148,052	296,104	444,156	592,209	740,261	888,313	1,036,365
1,800,000	152,302	304,604	456,906	609,209	761,511	913,813	1,066,115
1,850,000	156,552	313,104	469,656	626,209	782,761	939,313	1,095,865
1,900,000	160,802	321,604	482,406	643,209	804,011	964,813	1,125,615
1,950,000	165,052	330,104	495,156	660,209	825,261	990,313	1,155,365
2,000,000	169,302	338,604	507,906	677,209	846,511	1,015,813	1,185,115

Additional past service credits or accelerated service benefits must be approved by the Board. No accelerated service credits have been authorized. Additional past service credits authorized by the Board for the three named executive officers who participate in the EBP are noted in the table below. Information on the Qualified and Non-Qualified Defined Contribution Plan contributions for the other two named executive officers, Mr. Otten and Mr. Sugalski, is included in the Summary Compensation Table on page 127.

Name	Years of Credit Service[1] (#)	Final Average Earnings[1] ($)	Accrued Annual Pension Benefit[1] ($)
Charles W. Fischer	20.58[2]	1,140,139	396,100
Marvin F. Romanow	17.50[2]	624,167	205,900
Laurence Murphy	18.67	492,267	153,600

Notes:
1 All information as of December 31, 2004.
2 Ten years of additional past service credits were granted to both Mr. Fischer and Mr. Romanow by the Board in 2001.

Compensation Committee Interlocks and Insider Participation

The members of the Compensation and Human Resources Committee are set out in the table on page 124. Mr. Saville, a member of the Compensation and Human Resources Committee, had a relationship requiring disclosure, the details of which are set out under "Certain Relationships" on page 137. There were no compensation committee interlocks during 2004.

Change of Control Agreements

Nexen has entered into Change of Control Agreements with Messrs. Fischer, Romanow, Otten, Sugalski, Murphy and other key executives. The agreements were effective October 1999, amended December 2000 and amended and restated December 2001. The agreements recognize that these executives are critical to Nexen's ongoing business. They recognize the need to retain the executives, protect them from employment interruption due to a change in control and treat them in a fair and equitable manner, consistent with industry standards.

For the purposes of these agreements, a change of control includes any acquisition of common shares or other securities that carry the right to cast more than 35% of the votes attaching to all common shares and, in general, any event, transaction or arrangement which results in a person or group exercising effective control of Nexen.

If the named executives are terminated following a change in control, they will be entitled to receive salary and benefits for a specified severance period. For Mr. Fischer and Mr. Romanow, the severance period is 36 months. They may also terminate their employment on a voluntary basis following a change of control with severance periods of 36 and 30 months, respectively. For Messrs. Otten, Sugalski and Murphy, the severance period is 30 months.

Director Compensation

In December 2004, all director compensation was reviewed and confirmed at the then current levels. All directors who are not employees are paid:

Annual Board Chair Retainer	$150,000
Annual Board Retainer	$28,100
Annual Committee Retainer	$9,100
Additional Annual Committee Chair Retainer	$5,300
Board Committee Meeting Fees[1]	$1,800

Note:
1 Per meeting for attendance either in person or by telephone conference call.

Committee retainers are paid quarterly, in advance, and are pro-rated for partial service if appropriate.

Director	Annual Board Retainer	Annual Committee Retainers (Number of Committees)	Annual Committee Chair Retainer	Board Meeting Fees	Committee Meeting Fees	Total Fees
Charles W. Fischer[1]	n/a	n/a	n/a	n/a	n/a	n/a
Dennis G. Flanagan	$28,100	$36,400 (4)	$5,300	$14,400	$41,400	$125,600
David A. Hentschel	$28,100	$36,400 (4)	$5,300	$14,400	$37,800	$122,000
S. Barry Jackson	$28,100	$36,400 (4)	$5,300	$14,400	$37,800	$122,000
Kevin J. Jenkins	$28,100	$36,400 (4)	$5,300	$14,400	$41,400	$125,600
Eric P. Newell, O.C.[2]	$25,629	$24,900 (3)	-	$14,400	$27,000	$91,929
Thomas C. O'Neill[3]	$28,100	$36,400 (4)	-	$14,400	$39,600	$118,500
Francis M. Saville, Q.C.	$28,100	$36,400 (4)	$5,300	$14,400	$39,600	$123,800
Richard M. Thomson, O.C.[4]	$150,000	$36,400 (4)	-	$14,400	$41,400	$242,200
John M. Willson	$28,100	$36,400 (4)	$5,300	$12,600	$36,000	$118,400
Victor J. Zaleschuk	$28,100	$36,400 (4)	-	$14,400	$39,600	$118,500

Notes:
1 As an executive of Nexen, Mr. Fischer is not paid retainers or meeting fees.
2 Mr. Newell received all retainers and meeting fees in DSUs, except for meeting fees for two Board and three Committee meetings. His retainers were pro-rated to his appointment. As part of his orientation, he attended all Committee meetings held on February 11, 2004. He was appointed to three Committees the following day and it was determined to pay him meeting fees for the previous day for those three Committees as though he were a member at the time.
3 Mr. O'Neill received all meeting fees in DSUs for 2004.
4 Mr. Thomson received all retainers and meeting fees in DSUs from January 1, 2004 to April 1, 2004.

In 2001, a Deferred Share Unit (DSU) plan was approved as an alternative form of compensation for non-employee directors. Under the plan, eligible directors may elect annually to receive all or part of their fees in the form of DSUs, rather than cash. A DSU is a bookkeeping entry which tracks the value of one Nexen common share. DSUs are not paid out until the director leaves the Board, providing an ongoing equity stake in Nexen during the director's term of service. Payments of DSUs may be made in cash or in Nexen common shares purchased on the open market at the time of payment, at Nexen's option.

In 2003, the Board adopted a policy setting out that non-executive directors would no longer be granted stock options and non-executive directors are not eligible to receive options under the Tandem Option Plan. DSUs have since been employed as an alternate type of performance-based compensation. In December 2004, all directors who were not employees of Nexen were granted 2,100 DSUs, except for the Board Chair, who was granted 3,200 DSUs. The value of the grants was $106,827 and $162,784, respectively, at the closing market price of Nexen shares on the TSX on December 6, 2004 of $50.87.

Director	DSUs Held as of December 31, 2004
Charles W. Fischer	None
Dennis G. Flanagan	4,217
David A. Hentschel	4,217
S. Barry Jackson	4,217
Kevin J. Jenkins	7,443
Eric P. Newell, O.C.	5,823
Thomas C. O'Neill	6,664
Francis M. Saville, Q.C.	4,217
Richard M. Thomson, O.C.	7,589
John M. Willson	7,299
Victor J. Zaleschuk	4,217

Directors' and Officers' Liability Insurance

Nexen maintains a directors' and officers' liability insurance policy for the benefit of our directors and officers. The policy provides coverage for costs incurred to defend and settle claims against directors and officers to an annual limit of US$130 million with a US$1 million deductible per occurrence. The cost of coverage for 2004 was approximately US$0.8 million.

Share Ownership Guidelines for Directors

The Board believes it is important that directors demonstrate their commitment through share ownership. The Board has approved guidelines setting out that directors are expected to own or control at least 3,000 shares (DSUs count towards share ownership), to be accumulated over three years. Specific arrangements may be made when a qualified candidate might be prevented from serving by this guideline. The guideline is reviewed by the Board from time to time. At the time of writing, all directors meet the ownership requirements.

COMPENSATION AND HUMAN RESOURCES COMMITTEE

The Compensation and Human Resources Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to (i) key compensation and human resources policies; (ii) CEO and executive management compensation; and, (iii) executive management succession and development.

The Committee oversees Nexen's Incentive Compensation Plan, TOP Plan, Stock Appreciation Rights (StARs) Plan and Pension Plan. It reviews and approves executive management's recommendations for the annual salaries, bonuses and grants of TOPS and StARs. The Committee reports to the Board and the Board gives final approval to compensation matters.

The Committee evaluates the performance of the CEO and recommends his compensation which is approved by the independent directors of the Board.

Policies of the Committee

Nexen's policies and practices are linked to strategic business objectives and increased shareholder returns. Within that framework, the Committee's goal is to compensate executives based on performance, at a level competitive with the market and in a manner that would attract and retain a talented leadership team who are focused on managing Nexen's operations, finances and assets.

To ensure competitiveness, Nexen uses compensation surveys to compare executive compensation practices to peers, primarily major Canadian oil and gas companies and, where relevant, chemical and marketing companies. The Committee receives a report on CEO compensation from its own independent consultant, from time to time. The report includes competitive compensation data from a predetermined list of peer companies. The information is used as the basis for the Committee's annual compensation recommendation for the CEO.

Compensation Objectives

The compensation programs are designed to meet performance and competitiveness objectives.

Programs are pay-for-performance plans, with the level of rewards directly linked to planned performance for Nexen and its divisions. Individual performance and contributions are considered in making awards. Measures are aligned with goals and shareholder interests.

Competitiveness is assessed using compensation survey information from peers, including energy companies with whom Nexen competes for talent. Total compensation is assessed, while also considering the competitiveness of each component.

The compensation program has three components: base salary, annual cash incentives and long-term incentives. The Committee's goal is to provide total compensation for experienced top performing employees between the 50th and 75th percentile as compared to compensation levels of peer companies. Nexen's position against the market is reviewed on an annual basis.

Base Salaries

To determine base salaries, Nexen maintains a framework of job levels based on internal comparability and external market data. Base salary decisions are determined by considering the individual's current and sustained performance results, skills and potential.

Annual Incentives

The Board approves awards under the Annual Incentive Plan. The Committee determines the total amount of cash available for annual incentive awards by evaluating a combination of financial and non-financial criteria, including net income, cash flow and specific goals outlined in a balanced scorecard. The indicators, net income and cash flow, are commonly used metrics in our industry and each contributes one-quarter of the overall assessment. The qualitative assessment of the balanced scorecard performance indicators provides a comprehensive evaluation and accounts for the remaining one-half of the overall performance assessment. It includes qualitative and quantitative targets for growth and operating performance, such as net asset value growth, cost management, safety record, production volumes and reserves growth, among others. Another important measure in the scorecard is the extent to which the operations were conducted in an environmentally safe and socially responsible manner.

The purpose of annual incentives are to provide cash compensation that is at-risk and depends on the achievement of business and operating objectives. Individual target award levels increase in relation to job responsibilities so that the ratio of at-risk compensation versus fixed compensation is greater for higher levels of management. Individual awards are intended to reflect a combination of overall Nexen, personal and business unit performance, along with market competitiveness. Annual incentive payments vary within a range of 0% to approximately 200% of targeted awards.

The incentive plan is reviewed annually to ensure it continues to attract, motivate, reward and retain the high-performing and high-potential employees needed to achieve Nexen's business objectives, while reflecting long-term fiscal responsibility to our shareholders.

Stock and Long-Term Incentives

The Board believes that employees should have a stake in Nexen's future and that their interest should be aligned with the interest of our shareholders. To this end, Nexen's contributions to employee savings plans are made in Nexen common shares. In addition, the Committee selects those officers and employees whose decisions and actions can most directly impact business results to participate in the TOP and the StARs plans.

Under these plans, participating officers and employees receive grants of TOPs or StARs as a long-term incentive to increase shareholder value. The StARs Plan was introduced in 2001 and the TOP Plan (which is described on page 127) was introduced in 2004. For employees at or below mid-level department managers, StARs are typically granted instead of TOPs. The grants have a five-year term and vest one-third for each of the first three years of their term on the anniversary date of the grant. Awards of TOPs and StARs are supplementary to the Annual Incentive Plan and are intended to increase the pay-at-risk component. TOPS do not provide employees the right to vote the shares that are the subject of the TOPs.

To determine the number of TOPs and StARs available for distribution, we consider market information on options and other forms of long-term incentives and the impact of the programs on the level of dilution to shareholders. The focus in 2004 was on providing differentiated awards based on performance, potential and retention risk. The total TOPs granted and shares reserved for issue under all of our stock-based compensation programs will not exceed 10% of our total outstanding shares.

Effective July 1, 2004 the shareholders approved the conversion of Nexen's previous Stock Option Plan to the TOP Plan. The TOP Plan allows employees to exchange their TOPs for a cash payment, instead of exercising them for shares, if they choose to do so. No shares are issued when employees exchange their TOPs for a cash payment, which reduces further shareholder dilution over time.

The *American Jobs Creation Act of 2004* was signed into law on October 22, 2004 and contained some unexpected additions that affect deferred compensation for employees, including Nexen's TOPs. The new law requires employees who receive options with a cash payment feature to recognize the taxable income and, in some cases, pay penalties as soon as the options vest, even if they are not exercised at that time. Nexen believed that this change disadvantaged our US employees and diminished the value of TOPs as a long-term incentive for them.

In order to ease this less favorable tax treatment for US employees, the Board, as allowed under the terms of the TOP Plan, granted options without a cash payment feature to US employees in the December 2004 grant program. Nexen anticipates that it will continue to grant this type of modified TOP to US employees so that they are not disadvantaged in comparison to our other employees.

Executive Officer Share Ownership Guidelines

Executive officers are required to demonstrate their commitment to Nexen through share ownership and the Board has approved the officer shareholding guidelines set out below. The period to accumulate the shares is five years and shareholdings include the net value of exercisable options, flow-through shares, shares purchased and held within the Nexen Savings Plan and any other personal holdings. The guidelines are reviewed from time to time.

Position	Required Shareholdings
President and CEO	Three times annual salary
CFO	Two times annual salary
Other Executive Officers	One times annual salary

President and Chief Executive Officer Compensation

Competitive compensation information for our President and CEO is determined based on assessments conducted by independent compensation consulting firms which compare similar positions in the oil and gas industry. Target total cash compensation (base salary plus incentive bonus) is competitive within the range of the oil and gas comparator group.

Mr. Fischer's responsibility is to provide direction and leadership in setting and achieving goals which will create value for Nexen's shareholders in the short-term and the long-term. More specifically, the goals in 2004 for the CEO were to:

- Develop and execute the corporate strategy, balancing short-term growth while positioning Nexen for continued future growth;
- Achieve the targets for cash flow, production, net asset value, earnings per share, cash flow per share and reserve replacement as set out in the annual operating plan;
- Maintain financial flexibility and liquidity to support business strategies without undue financial risk for shareholders;
- Achieve operating, finding and development and general and administrative cost performance targets set out in the annual operating plan;
- Achieve top quartile performance in safety, environmental performance and social responsibility; and
- Provide for corporate management succession and development.

Based on the Board assessment of Mr. Fischer's achievement of objectives in 2003, his base salary was increased to $850,000 in April 2004 and $900,000 in July 2004 after an extensive competitive market review. He was awarded a bonus of $860,000 under the Annual Incentive Plan, which was 176% of his target bonus.

Mr. Fischer was also granted options to purchase 150,000 shares at an exercise price of $50.87 under the Nexen TOP Plan. Awards under the TOP Plan are a direct link to share performance and form a part of the competitive overall compensation package.

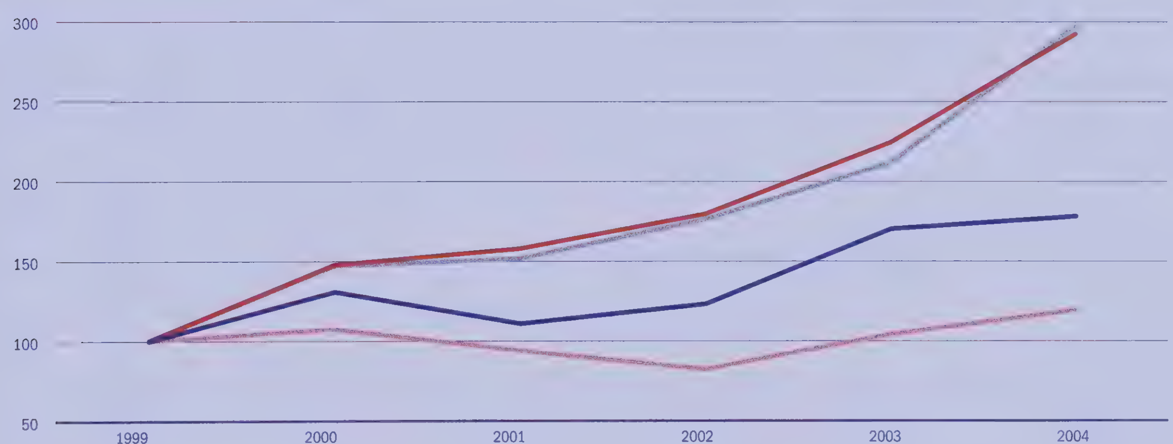
Submitted on behalf of the Compensation and Human Resources Committee:

John Willson, Chair
Dave Hentschel
Barry Jackson
Francis Saville
Dick Thomson
Vic Zaleschuk

Share Performance Graph

The following graph shows changes in the past five year period, ending December 31, 2004 in the value of $100 invested in our common shares, compared to the S&P/TSX Composite Index, the S&P/TSX Energy Sector Index and the S&P/TSX Oil & Gas Exploration & Production Index as at December 31, 2004. Our common shares are included in each of these indices.

Total Return Index Values



	1999/12	2000/12	2001/12	2002/12	2003/12	2004/12
Nexen Inc.	100.00	130.86	110.92	123.22	170.29	178.13
S&P/TSX Energy Sector Index	100.00	147.69	157.90	179.60	224.43	292.41
S&P/TSX Oil & Gas Exploration & Production Index	100.00	147.04	151.79	176.33	211.85	298.03
S&P/TSX Composite Index	100.00	107.41	93.91	82.23	104.20	119.20

Assuming an investment of $100 and the reinvestment of dividends

Item 12. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

Nexen's common shares are the only class of voting securities. Based on information known to Nexen, the following table shows each person or group who beneficially owns (pursuant to SEC Regulations) more than 5% of Nexen's voting securities at December 31, 2004.

Name and Address of Beneficial Owner	# of Shares Beneficially Owned	% of Shares
Jarislowsky Fraser Limited[1] Suite 2005, 1010 Sherbrooke Street West Montreal, Quebec, Canada, H3A 2R7	21,148,998	16.4
Ontario Teachers' Pension Plan Board[2] 5650 Yonge Street Toronto, Ontario, Canada, M2M 4H5	19,349,618	15.0
Capital Research and Management Co.[3] 333 South Hope Street, 53 Floor Los Angeles, California, USA, 90071-1406	9,326,080	7.2

Notes:
1 The beneficial owner has sole voting power over 17,878,438 shares, shared voting power over 3,270,560 shares; and sole power to dispose of all shares.
2 The beneficial owner has sole voting and power to dispose of all shares.
3 The beneficial owner has sole power to dispose of all shares and disclaims beneficial ownership pursuant to Rule 13d-4.

SECURITY OWNERSHIP OF MANAGEMENT

At February 22, 2005, the following directors, certain executive officers, and all directors and executive officers as a group beneficially owned the following Nexen common shares:

Name of Beneficial Owner	Number of Shares[1]	Exercisable Stock Options[2]
Charles W. Fischer	33,651	514,000
Dennis G. Flanagan	6,001	13,960
David A. Hentschel	5,656	35,185
S. Barry Jackson	6,000	10,185
Kevin J. Jenkins	3,068	18,685
Eric P. Newell, O.C.	3,000	Nil
Thomas C. O'Neill	4,000	3,685
Francis M. Saville, Q.C.	10,400	27,936
Richard M. Thomson, O.C.	23,001	52,861
John M. Willson	7,001	25,185
Victor J. Zaleschuk	15,675	70,185
Laurence Murphy	13,574	52,580
Douglas B. Otten	28,072	85,958
Marvin F. Romanow	23,998	202,200
Thomas A. Sugalski	17	35,800
All directors and executive officers as a group (22 persons)	227,375	1,395,642

Notes:
1 The number of shares held and options exercisable by each beneficial owner represents less than 1% of the shares outstanding.
2 Includes all options exercisable within 60 days of February 22, 2005. All options held by non-executive directors are vested.

Under the terms of our TOP Plan, the Board of Directors may grant options to officers and employees and, when previously allowed for, to directors. Nexen does not receive any consideration when options are granted.

Equity Compensation Plan Information:

	Number of securities to be issued upon exercise of outstanding options (a)	Weighted-average exercise price of outstanding options (b)	Number of securities remaining available for future issuance under equity compensation plans (c)
Equity compensation plans approved by shareholders	8,138,183	$39	9,586,237

Item 13. Certain Relationships and Related Transactions

Mr. Saville, a director, was a senior partner of Fraser Milner Casgrain LLP (FMC), Barristers and Solicitors, Calgary, Alberta until the end of January 2004. Since February 1, 2004, he has been counsel with the firm. FMC has rendered legal services to Nexen during each of the last five years. Mr. Saville neither solicits nor participates in the services rendered to Nexen and does not receive any portion or percentage of the fees paid to FMC. In addition, he is independent pursuant to our Categorical Standards.

Item 14. Principal Accounting Fees and Services

In connection with their responsibilities, the Audit and Conduct Review Committee:

- met with management and the independent auditor to review and discuss the December 31, 2004 consolidated financial statements,
- discussed with the independent auditor the matters required by Canadian regulators in accordance with Section 5751 of the General Assurance and Auditing Standards of the Canadian Institute of Chartered Accountants *Communications with Those Having Oversight Responsibility for the Financial Reporting Process* and by US regulators in accordance with the Statement on Auditing Standards No. 61 *Communication with Audit Committees* issued by the American Institute of Certified Public Accountants,
- received written disclosures from the independent auditor required by the SEC in accordance with the Independence Standards Board Standard No. 1 *Independence Discussions with Audit Committees*,
- discussed with the independent auditor that firm's independence, and
- oversaw the progress of the Section 404 Sarbanes-Oxley project for management and the independent auditor to report on the effectiveness of internal control over financial reporting as at December 31, 2004.

AUDIT FEES

Fees billed by Deloitte & Touche LLP were:

- $1,041,000 for the completion of the 2003 audit ($641,000) and commencement of the 2004 audit ($400,000) of the Consolidated Financial Statements included in our Annual Report on Form 10-K (2003 billings—$596,000).
- $45,000 for the 2004 first, second and third quarter reviews ($42,000 for the 2003 first, second and third quarter reviews) of the Consolidated Financial Statements included on Form 10-Qs.
- $630,000 (nil for 2003) for the commencement of the 2004 audit of internal control over financial reporting.

AUDIT-RELATED FEES

Fees billed by Deloitte & Touche LLP were:

- $296,000 for 2004 ($322,000 for 2003) for the annual audits of our subsidiary financial statements and employee benefit plans.
- $9,500 for 2004 ($87,000 for 2003) for comfort letters to securities commissions.

TAX FEES

Fees billed by Deloitte & Touche LLP were $60,000 for 2004 ($160,000 for 2003) for tax return preparation assistance and tax-related consultation.

ALL OTHER FEES

No other fees were billed by Deloitte & Touche LLP during 2004 and 2003.

AUDIT COMMITTEE APPROVAL

Before Deloitte & Touche LLP is engaged by Nexen or our subsidiaries to render audit or non-audit services, the engagement is approved by Nexen's Audit and Conduct Review Committee. All audit-related and tax services provided by Deloitte & Touche LLP since May 6, 2003 have been approved by the Audit and Conduct Review Committee.

Submitted on behalf of the Audit and Conduct Review Committee:

Dave Hentschel, Chair
Dennis Flanagan
Barry Jackson
Kevin Jenkins
Tom O'Neill
Dick Thomson

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

FINANCIAL STATEMENTS AND SCHEDULES

We refer you to the Index to Financial Statements and Related Information under Item 8 of this report where these documents are listed.

Schedules and separate financial statements of subsidiaries are omitted because they are not required or applicable, or the required information is shown in the Consolidated Financial Statements or notes.

EXHIBITS

Exhibits filed as part of this report are listed below. Certain exhibits have been previously filed with the Commission and are incorporated in this Form 10-K by reference. Instruments defining the rights of holders of debt securities that do not exceed 10% of Nexen's consolidated assets have not been included. A copy of such instruments will be furnished to the Commission upon request.

2.2 Agreement for the Sale and Purchase of EnCana (UK) Limited, between EnCana (UK) Holdings Limited and Nexen Energy Holdings International Limited dated October 28, 2004 (filed as Exhibit 2.1 to Form 8-K dated October 29, 2004, filed by the Registrant).

3.5 Restated Certificate of Incorporation of the Registrant dated June 5, 1995, and Restated Articles of Incorporation (filed as Exhibit 3.5 to Form 10-K for the year ended December 31, 1995, filed by the Registrant).

3.6 Certificate of Amendment of the Articles of the Registrant dated May 9, 1996 (filed as Exhibit 3.6 to Form 10-K for the year ended December 31, 1996, filed by the Registrant).

3.7 Certificate of Amendment and Articles of Amendment of the Registrant dated November 2, 2000, with respect to the name change to Nexen Inc. (filed as Exhibit 3.7 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

3.8 By-Law No. 1 of the Registrant enacted February 15, 2002, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 2 to Form 8-A/A dated August 20, 2002, filed by the Registrant).

3.9 By-Law No. 2 of the Registrant enacted December 9, 2003, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 3.9 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

3.10 Certificate of Amalgamation dated January 1, 2005 relating to the amalgamation of Nexen Canada Ltd., a wholly-owned subsidiary of the Registrant, into the Registrant (filed as Exhibit 1 to Form 8-K dated February 4, 2005, filed by the Registrant).

3.11 Amended Articles of Amalgamation dated January 13, 2005 relating to the amalgamation of Nexen Canada Ltd., a wholly-owned subsidiary of the Registrant, into the Registrant (filed as Exhibit 2 to Form 8-K dated February 4, 2005, filed by the Registrant).

4.29 Acquisition Agreement between the Registrant, Occidental Petroleum Corporation and Ontario Teachers' Pension Plan Board, dated March 1, 2000 (filed as Exhibit 4.29 to Form 10-K for the year ended December 31, 1999, filed by the Registrant).

4.32 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated November 17, 2000, amending the amount of the facility to $400 million and providing for various conforming covenant amendments to the Loan Agreement dated April 14, 1997 (as restated) (filed as Exhibit 4.32 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

4.33 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders dated October 16, 2000, reducing the amount of the facility to $975 million and splitting the loan into 364 day (40%) and six-year term (60%) portions, and other various amendments (filed as Exhibit 4.33 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

4.36 First Amending Agreement to the October 16, 2000 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated July 31, 2001 (filed as Exhibit 4.36 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

4.37 First Amending Agreement to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated August 1, 2001 (filed as Exhibit 4.37 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

4.38 Second Amending Agreement to the October 16, 2000 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated July 30, 2002 (filed as Exhibit 4.38 to Form 10-K for the year ended December 31, 2002, filed by the Registrant).

4.39 Second Amending Agreement to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated July 31, 2002 (filed as Exhibit 4.39 to Form 10-K for the year ended December 31, 2002, filed by the Registrant).

4.40 Amended and Restated Shareholder Rights Plan Agreement dated May 2, 2002 between the Registrant and CIBC Mellon Trust Company, as Rights Agent, which includes the Form of Rights Certificate as Exhibit A (filed as Exhibit 3 to Form 8-A/A dated August 20, 2002, filed by the Registrant).

4.42 Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company providing for the issue of debt securities from time to time (filed as Exhibit 4.42 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.43 First Supplemental Indenture dated April 28, 1998 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$200 million, 7.40% notes due 2028 (filed as Exhibit 4.43 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.44 Third Amending Agreement dated July 29, 2003 to the October 16, 2000 Restated Loan Agreement of April 14, 1997 between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.44 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.45 Third Amending Agreement dated July 29, 2003 to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.45 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.46 Third Supplemental Indenture dated March 11, 2002 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of $500 million, 7.85% notes due 2032 (filed as Exhibit 4.46 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.47 Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issue of subordinated notes from time to time (filed as Exhibit 4.47 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.48 Officer's Certificate dated November 4, 2003 pursuant to the Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issuance of US$460 million, 7.35% subordinated notes due 2043 (filed as Exhibit 4.48 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.49 Fourth Amending Agreement dated November 4, 2003 to the October 16, 2003 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.49 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.50 Fourth Amending Agreement dated November 4, 2003 to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.50 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.51 Fourth Supplemental Indenture dated November 20, 2003 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$500 million, 5.05% notes due 2013 (filed as Exhibit 4.51 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

4.52 Loan Agreement of November 26, 2004, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.1 to Form 8-K dated December 7, 2004, filed by the Registrant).

10.40 Amended and Restated Change of Control Agreements with Executive Officers dated during December, 2001 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

10.41 Indemnification Agreements made between the Registrant and its directors and officers during 2002 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2002, filed by the Registrant).

10.42 Indemnification Agreement made between the Registrant and one of its directors, Eric P. Newell, as of January 5, 2004 (filed as Exhibit 10.42 to Form 10-K for the year ended December 31, 2003, filed by the Registrant).

11.2 Statement regarding the Computation of Per Share Earnings for the three years ended December 31, 2004.

16.1 Letter re change in certifying accountant (filed as Exhibit 16.1 to Form 8-K filed July 17, 2002 by the Registrant).

21.0 Subsidiaries of the Registrant.

23.0 Consent of Independent Registered Chartered Accountants.

31.2 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of periodic report by Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of periodic report by Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.1 Opinion of Internal Qualified Reserves Evaluator on National Instrument 51-101 Form F2 as required by certain Canadian securities regulatory authorities.

REPORTS ON FORM 8-K

During the quarter ended December 31, 2004, we filed or furnished the following reports on Form 8-K:

- Current report on Form 8-K dated October 14, 2004, to furnish our press release announcing our 2004 third quarter results.
- Current report on Form 8-K dated November 3, 2004, to announce an agreement with a wholly-owned subsidiary of EnCana Corporation to acquire EnCana (UK) Limited.
- Current report on Form 8-K dated December 7, 2004, to announce the completion of the acquisition of EnCana (UK) Limited.

Up until the filing of this Form 10-K, during 2005, we filed or furnished the following reports on Form 8-K:

- Current report on Form 8-K/A dated January 12, 2005, to file the pro forma financial information in connection with the acquisition of EnCana (UK) Limited.
- Current report on Form 8-K dated February 4, 2005, to file our Certificate and Amended Articles of Amalgamation.
- Current report on Form 8-K dated February 10, 2005, to furnish our press release announcing our 2004 annual reserves and annual results.
- Current report on Form 8-K/A Amendment No. 2 dated February 25, 2005 to file the amended pro forma financial information in connection with the acquisition of Encana (UK) Limited.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 1, 2005.

NEXEN INC.

By: /s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 1, 2005.

/s/ Dennis G. Flanagan
Dennis G. Flanagan, Director

/s/ David A. Hentschel
David A. Hentschel, Director

/s/ S. Barry Jackson
S. Barry Jackson, Director

/s/ Kevin J. Jenkins
Kevin J. Jenkins, Director

/s/ Eric P. Newell
Eric P. Newell, Director

/s/ Thomas C. O'Neill
Thomas C. O'Neill, Director

/s/ Francis M. Saville
Francis M. Saville, Director

/s/ Richard M. Thomson
Richard M. Thomson, Director

/s/ John M. Willson
John M. Willson, Director

/s/ Victor J. Zaleschuk
Victor J. Zaleschuk, Director

/s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Michael J. Harris
Michael J. Harris
Controller
(Principal Accounting Officer)

/s/ John B. McWilliams
John B. McWilliams
Senior Vice President, General Counsel
and Secretary

/s/ Kevin J. Reinhart
Kevin J. Reinhart
Vice President, Corporate Planning
and Business Development

EXHIBIT 31.1

Certifications

I, Charles W. Fischer, President and Chief Executive Officer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is likely to materially affect, the registrant's internal control over financial reporting; and;
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2005

/s/ Charles W. Fischer
Charles W. Fischer
President, and Chief Executive Officer

EXHIBIT 31.2

Certifications

I, Marvin F. Romanow, Executive Vice-President and Chief Financial Officer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and we have:
   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is likely to materially affect, the registrant's internal control over financial reporting; and;
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2005

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President,
and Chief Financial Officer

EXHIBIT 32.1

Certification Of Periodic Report

I, Charles W. Fischer, President and Chief Executive Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2005

/s/ Charles W. Fischer
Charles W. Fischer
President, and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

Certification Of Periodic Report

I, Marvin F. Romanow, Executive Vice President and Chief Financial Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2005

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President,
and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

corporate & other information

Fort Assiniboine, Alberta, Canada

Reserves—Before Royalties, Year-end Pricing

In 2004, we invested $4.3 billion and added 123 mmboe of proved reserves after revisions, more than replacing our production of 91 mmboe. Most of the proved reserves added in 2004 relate to the North Sea assets we acquired, mainly for Buzzard.

Negative revisions to proved reserves totaled 284 mmboe in 2004, 246 of which were bitumen barrels to our Long Lake Project. Under SEC regulations, we are required to represent these reserves as bitumen rather than the synthetic crude, and to use year-end pricing to determine proved reserves. On December 31, 2004, a combination of wide heavy oil differentials, high natural gas prices and very high diluent costs resulted in low bitumen netbacks. As a result, under these price assumptions, we wrote off all of our proved reserves for Long Lake at year-end 2004. This change has no financial impact. Under NI 51-101, the Canadian reserves standards, we would have reported 205 million barrels of proved synthetic reserves, not bitumen reserves, at year-end 2004.

In our core assets, we had negative revisions of 38 mmboe in our proved reserves, including 22 mmbbls in Yemen and 14 mmboe for heavy oil in Canada. In Yemen, this primarily related to the Camaal and Haru fields where performance was less than expected. Approximately one-third of the Canadian heavy oil reserve reductions resulted from low year-end heavy oil prices. The balance was due to performance on various properties. Again, these changes had no financial impact.

Investment in Core Asset Development

We invested $634 million primarily in the Gulf of Mexico, Masila in Yemen, and our Canadian conventional assets. These are maturing assets where our strategy focuses on maximizing value extraction, not just reserve additions. Approximately $465 million of this was invested to convert 61 mmboe (before revisions) of proved undeveloped and proved non-producing reserves to proved developed reserves (mostly Aspen, Gunnison and Masila). The remainder added approximately 18 mmboe of new proved reserves in Canada, Syncrude and shallow-water Gulf of Mexico. This investment is generating attractive returns and significant value for shareholders.

Proved + Probable Reserves
(%)

■ Yemen
■ North Sea
■ Other International
■ US
■ Canada Conventional
Canada Bitumen
■ Syncrude

Investment in New Growth Exploration

We invested $339 million in new growth exploration, yielding nominal additions to proved reserves. One quarter of this was invested in early-stage exploration activities. The balance was invested to drill 14 exploration wells. We had small discoveries at Tobago and Dawson Deep in the Gulf of Mexico, a significant discovery and successful appraisal in the area west of Usan on Nigeria's OPL-222, and two promising wells on Block 51 in Yemen. Some proved reserves were booked for Dawson Deep, but we didn't book proved reserves on OPL-222 or Tobago as they have not yet been sanctioned as commercial projects yet. The Block 51 wells require further testing to determine their reserve potential.

New Growth Development

We invested $682 million to advance our longer cycle-time development projects including Long Lake and Syncrude Stage 3 in Canada, Block 51 in Yemen and Buzzard in the North Sea. We added 17 mmboe of proved reserves, primarily from Syncrude. On Block 51 the majority of proved reserves were recognized in 2003.

To date, we have booked 190 million boe of proved reserves (Buzzard and Syncrude) and 612 mmboe of probable reserves (Long Lake, North Sea, Usan and Syncrude) related to these projects. The probable reserves alone amount to three-quarters of our current proved reserves and there are more possible reserves to book which we expect will contribute strong growth between 2005 and 2008.

Reserves—Before Royalties, Year-end Pricing

www.nexeninc.com

mmboe	Yemen Oil	International North Sea Oil	International North Sea Gas	Other Intl Oil	US Oil	US Gas	Canada Oil	Canada Gas	Canada Bitumen[4]	Total Oil and Gas	Mining Syncrude[3]	Total Oil, Gas and Mining
Proved Reserves[1]												
Dec. 31, 2003	192	-	-	11	75	51	114	78	5	526	285	811
Extensions and Discoveries	2	-	-	-	1	3	4	4	241	255	22	277
Acquisitions	-	126	4	-	-	-	1	-	-	131	-	131
Dispositions	-	-	-	-	-	-	(1)	-	-	(1)	-	(1)
Revisions	(22)	3	(2)	4	(5)	(2)	(13)	(1)	(246)	(284)	-	(284)
Production	(39)	(1)	-	(3)	(11)	(9)	(13)	(9)	-	(85)	(6)	(91)
Dec. 31, 2004	**133**	**128**	**2**	**12**	**60**	**43**	**92**	**72**	**0**	**542**	**301**	**843**
Probable Reserves[1,2]												
Dec. 31, 2003	95	-	-	64	21	12	38	14	395	639	85	724
Extensions and Discoveries and Conversions	-	-	-	21	1	-	(1)	2	(241)	(218)	(16)	(234)
Acquisitions	-	116	7	-	-	-	-	-	-	123	-	123
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Revisions	(46)	1	(1)	4	(16)	(4)	2	8	246	194	-	194
Dec. 31, 2004	**49**	**117**	**6**	**89**	**6**	**8**	**39**	**24**	**400**	**738**	**69**	**807**
Proved + Probable Reserves[1,2]												
Dec. 31, 2003	287	-	-	75	96	63	152	92	400	1,165	370	1,535
Extensions and Discoveries	2	-	-	21	2	3	3	6	-	37	6	43
Acquisitions	-	242	11	-	-	-	1	-	-	254	-	254
Dispositions	-	-	-	-	-	-	(1)	-	-	(1)	-	(1)
Revisions	(68)	4	(3)	8	(21)	(6)	(11)	7	-	(90)	-	(90)
Production	(39)	(1)	-	(3)	(11)	(9)	(13)	(9)	-	(85)	(6)	(91)
Dec. 31, 2004	**182**	**245**	**8**	**101**	**66**	**51**	**131**	**96**	**400**	**1,280**	**370**	**1,650**

Notes:

1 We internally evaluate all of our reserves and have at least 80% of our proved reserves audited by independent qualified consultants each year. Our reserves are also reviewed and approved by our Board of Directors. Reserves represent our working interest before royalties at year-end constant pricing using SEC rules. Gas is converted to equivalent oil at a 6:1 ratio.

2 Probable reserves are determined according to SPE/WPC definitions. US investors should read the Cautionary Note to US Investors on page 151.

3 US investors should read the Cautionary Note to US Investors on page 151.

4 Reserves at Long Lake at December 31, 2003 have been restated from synthetic (205 mmboe proved and 125 mmboe probable) to bitumen reserves.

2004 Oil & Gas and Syncrude Capital Investment[1] (Cdn$ millions)	Core Asset Development	New Growth Exploration[1]	New Growth Development	Acquisitions	Total
Canada	131	37	17	4	189
United States	267	162	-	-	429
International	186	121	158	2,583	3,048
Long Lake	-	19	343	-	362
Total Oil and Gas	584	339	518	2,587	4,038
Mining (Syncrude)	50	-	164	-	214
Total Oil & Gas and Syncrude Capital Investment	**634**	**339**	**682**	**2,587**	**4,242**

Notes:

1 Includes geological and geophysical expenditures of $73 million.

Historical Review (unaudited)

(Cdn$ millions, except per share and production data)	2004	2003	2002	2001	2000
Highlights					
Net Sales	3,176	2,844	2,341	2,356	2,425
Cash Flow from Operations	1,942	1,795	1,311	1,353	1,501
Per Common Share (Cdn$/share)	15.10	14.50	10.71	11.20	12.01
Net Income (Loss)	793	578	409	411	565
Per Common Share (Cdn$/share)	6.17	4.67	3.34	3.40	4.52
Capital Expenditures	1,681	1,494	1,625	1,404	915
Business Acquisitions	2,583	-	-	-	39
Dispositions	34	293	49	5	42
Production[1,2]					
Production Before Royalties (mboe/d)	250	269	269	268	256
Production After Royalties (mboe/d)	174	185	176	184	171
Financial Position					
Working Capital	40	1,399	69	24	179
Property, Plant and Equipment, Net	8,643	4,550	4,944	4,170	3,540
Total Assets	12,383	7,717	6,665	5,430	5,656
Net Debt[3]	4,219	1,690	2,527	2,218	2,059
Long-Term Debt	4,259	3,089	2,596	2,242	2,238
Shareholders' Equity	2,867	2,075	1,590	1,133	731
Shares and Dividends					
Common Shares Outstanding (millions)	129.2	125.6	123.0	121.2	119.9
Number of Common Shareholders	1,329	1,420	1,372	1,375	1,394
Closing Common Share Price (TSX) (Cdn$/share)	48.70	46.92	34.25	31.08	37.00
Dividends Declared per Common Share (Cdn$/share)	0.40	0.33	0.30	0.30	0.30
Cash Flow from Operations[4]					
Oil and Gas					
Yemen	581	530	492	445	480
Canada	426	490	460	477	544
United States	700	623	190	285	321
United Kingdom	30	-	-	-	-
Other Countries	57	64	151	121	178
Marketing	100	126	45	71	36
Syncrude	183	105	129	110	102
	2,077	1,938	1,467	1,509	1,661
Chemicals	82	74	79	83	80
	2,159	2,012	1,546	1,592	1,741
Interest and Other Corporate Items	(196)	(208)	(219)	(214)	(215)
Income Taxes	(21)	(9)	(16)	(25)	(25)
Total Cash Flow from Operations	**1,942**	**1,795**	**1,311**	**1,353**	**1,501**

Notes:
1 Production is Nexen's working interest share.
2 Natural gas is converted at 6 mcf per equivalent barrel of oil.
3 Net Debt is defined as long-term debt less working capital.
4 Cash flow from operations is defined as cash generated from operating activities before changes in non-cash working capital.

For more historical information, view our Statistical Supplement at www.nexeninc.com or contact Investor Relations: (403) 699-5273 or investor_relations@nexeninc.com

Historical Review (unaudited)

www.nexeninc.com

	2004	2003	2002	2001	2000
Production Before Royalties					
Crude Oil and NGLs (mbbls/d)					
Yemen	107.3	116.8	118.0	118.3	111.9
Canada	36.2	46.3	56.3	58.0	53.9
United States	30.0	28.3	9.9	10.0	11.1
Australia	2.7	6.1	12.8	10.2	12.0
United Kingdom	1.5	-	-	-	-
Other Countries	5.3	5.4	8.9	6.2	6.4
Syncrude	17.2	15.3	16.6	16.1	14.7
	200.2	218.2	222.5	218.8	210.0
Natural Gas (mmcf/d)					
Canada	146	158	167	174	161
United States	148	145	112	121	113
United Kingdom	3	-	-	-	-
	297	303	279	295	274
Total Production Before Royalties (mboe/d)	**250**	**269**	**269**	**268**	**256**
Production After Royalties					
Crude Oil and NGLs (mbbls/d)					
Yemen	53.5	57.5	55.8	55.5	50.7
Canada	28.2	35.4	43.4	48.3	44.0
United States	26.5	25.0	8.2	8.3	9.3
Australia	2.5	5.6	10.3	9.6	12.0
United Kingdom	1.5	-	-	-	-
Other Countries	4.7	4.6	5.2	5.3	5.4
Syncrude	16.6	15.2	16.5	15.5	12.1
	133.5	143.3	139.4	142.5	133.5
Natural Gas (mmcf/d)					
Canada	115	125	128	147	135
United States	126	122	93	99	92
United Kingdom	3	-	-	-	-
	244	247	221	246	227
Total Production After Royalties (mboe/d)	**174**	**185**	**176**	**184**	**171**
Oil and Gas Cash Netback[1] ($/boe)					
Yemen	14.99	12.58	11.59	10.37	11.67
Canada	21.24	19.46	15.67	15.47	19.05
United States	35.35	32.48	19.30	26.56	29.73
Australia	14.28	21.10	22.66	22.85	34.13
United Kingdom	39.19	-	-	-	-
Syncrude	31.07	20.92	22.43	18.75	18.73
Company-Wide Oil and Gas	**22.66**	**19.24**	**15.06**	**15.05**	**17.82**

Notes:

1 Defined as average sales price less royalties and other, and operating costs, and in country taxes in Yemen, calculated using our working interest production before royalties. Calculation details can be found on page 45 and in the Statistical Supplement on our website.

Corporate Information

Directors

Charles W. Fischer

Dennis G. Flanagan

David A. Hentschel

S. Barry Jackson

Kevin J. Jenkins

Eric P. Newell, O.C.

Thomas C. O'Neill

Francis M. Saville, Q.C.

Richard M. Thomson, O.C.

John M. Willson

Victor J. Zaleschuk

For more information on our officers and directors, please see Item 10 in our Form 10-K.

Auditors

Deloitte & Touche LLP
Calgary, Alberta

Common Share Transfer Agent and Registrars

CIBC Mellon Trust Company
Calgary, Toronto, Montreal, Regina, Winnipeg, Vancouver and Halifax

Mellon Investor Service
New York, NY

Stock Symbol—NXY

Toronto Stock Exchange

New York Stock Exchange

Dividend Reinvestment Plan

A copy of the offering circular (and for United States residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1-800-387-0825 or on the internet at www.cibcmellon.ca

Officers

Richard M. Thomson
Chair of the Board

Charles W. Fischer
President and Chief Executive Officer

Marvin F. Romanow
Executive Vice President and Chief Financial Officer

John B. McWilliams, Q.C.
Senior Vice President, General Counsel and Secretary

Laurence Murphy
Senior Vice President, International Oil and Gas

Douglas B. Otten
Senior Vice President, United States Oil and Gas

Thomas A. Sugalski
Senior Vice President, Chemicals

Roger D. Thomas
Senior Vice President, Canadian Oil and Gas

Nancy F. Foster
Vice President, Human Resources and Corporate Services

Gary H. Nieuwenburg
Vice President, Synthetic Crude

Kevin J. Reinhart
Vice President, Corporate Planning and Business Development

Una M. Power
Treasurer

Michael J. Harris
Controller

Rick C. Beingessner
Assistant Secretary

Sylvia L. Groves
Assistant Secretary

Head Office

801 7th Avenue S.W.
Calgary, Alberta, Canada T2P 3P7
T. (403) 699-4000
F. (403) 699-5800
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Operating Entities

Chemicals

Nexen Chemicals Canada Limited Partnership

Nexen Chemicals USA

Nexen Química Brasil Ltda.

Marketing

Nexen Marketing

Nexen Marketing International Ltd.

Nexen Marketing Singapore Pte. Ltd.

Nexen Marketing USA Inc.

Canada

Nexen Petroleum Canada

United States

Nexen Petroleum Offshore USA Inc.

Nexen Petroleum USA Inc.

International

Canadian Nexen Petroleum Yemen

Nexen E & P Services Nigeria Limited

Nexen Ettrick UK Limited

Nexen Exploration UK Limited

Nexen Petroleum Colombia Limited

Nexen Petroleum do Brasil Ltda.

Nexen Petroleum Equatorial Guinea Limited

Nexen Petroleum Nigeria Limited

Nexen Petroleum UK Limited

Corporate Information

www.nexeninc.com

Forward-Looking Information

Certain statements in this report are "forward-looking statements" within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, as amended. Forward-looking statements are generally identifiable by terms such as "intend", "plan", "expect", "estimate", "budget" or other similar words. The forward-looking statements are subject to known and unknown risks and uncertainties, and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied. Please read item 7 and the note regarding forward-looking statements in our Form 10-K on page 71 for a full discussion of the risks and uncertainties associated with our business.

Cautionary Note to US Investors

The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to discuss only proved reserves that are supported by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. In this report, excluding the Form 10-K, we may refer to "recoverable reserves", "probable reserves" and "recoverable resources" which are inherently more uncertain than proved reserves. These terms are not used in our filings with the SEC. Our reserves and related performance measures represent our working interest before royalties, unless otherwise indicated.

In addition, under SEC regulations, the Syncrude oil sands operations are considered mining activities rather than oil and gas activities. Production, reserves and related measures in this report include results from the Company's share of Syncrude.

Cautionary Note to Canadian Investors

Nexen is required to disclose oil and gas activities under *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101). However, the Canadian securities regulatory authorities (CSA) have granted us exemptions from certain provisions of NI 51-101 to permit US style disclosure. These exemptions were sought because we are a SEC Registrant and our securities regulatory disclosures, including Form 10-K and other related forms, must comply with SEC requirements. Our disclosures may differ from those Canadian companies who have not received similar exemptions under NI 51-101.

Our probable reserves disclosure applies the Society of Petroleum Engineers/World Petroleum Council (SPE/WPC) definition for probable reserves. *The Canadian Oil and Gas Evaluation Handbook* states there should not be a significant difference in estimated probable reserve quantities using the SPE/WPC definition versus NI 51-101.

Please read the "Special Note to Canadian Investors" in Item 7A in our Form 10-K, for a summary of the exemption granted by the CSA and the major differences between SEC requirements and NI 51-101. The summary is not intended to be all-inclusive nor to convey specific advice. Reserve estimation is highly technical and requires professional collaboration and judgement. The differences between SEC requirements and NI 51-101 may be material.

Conversions

Natural gas is converted at 6 mcf per equivalent barrel of oil.

Dollar Amounts

In Canadian dollars unless otherwise stated.

Duplicate Reports

Although we strive to ensure our registered shareholders receive only one copy of this annual report, duplication is unavoidable if securities are registered in multiple accounts under different names and addresses. If you received duplicates, please call CIBC Mellon at 1-800-387-0825.

Annual General Meeting

The Annual General and Special Meeting of Shareholders will be held on Wednesday April 27, 2005 at 11:00 a.m. Mountain Time, in the Crystal Ballroom at the Fairmont Palliser Hotel in Calgary, Alberta, Canada.

Expected Earnings Dates

Q1—April 27, 2005

Q2—July 14, 2005

Q3—October 13, 2005

Q4—February 17, 2006

Investor Relations Contact

Grant Dreger
T. (403) 699-5273
F. (403) 699-5730
grant_dreger@nexeninc.com

Website

Nexen's statistical supplement and other financial documents are available online at www.nexeninc.com. Hard copies may be ordered through the Investor Centre on our website or by calling (403) 699-5931.

Feedback

We welcome your feedback on this report. Please email annual_report@nexeninc.com or phone (403) 699-4791.

Sustainability Report

Nexen produces a Sustainability Report that outlines our safety, environment and social responsibility performance. For more information, call Jeff Flood at (403) 699-5469.

Abbreviations

bbl	barrel
bbls/d	barrels of oil per day
bcf	billion cubic feet
boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
F&D	finding and development
G&A	general and administrative
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent
mmboe	million barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
WTI	West Texas Intermediate

designed and produced by nonfiction studios inc.

In three years, Nexen will be producing more higher-margin barrels in the Gulf of Mexico and North Sea. We'll be leading the oil sands development and maximizing value from Yemen. We'll be developing new opportunities for growth. Our strategy gets us from here to there: investing wisely today to create shareholder value over the long term.

< see the value

nexen

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